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PROPOSED
REGULATIONS
1977–1981

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

E2.18/3:

Proposed Regulations

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Proposed Regulations

Note: Although established October 1, 1977, the Federal Energy Regulatory Commission did not issue proposed regulations until March 21, 1978.

43 Federal Register (1978)

¶ 31,987 Valuation of Common Carrier Pipe Lines

43 F.R. 11725 (March 21, 1978).

[49 CFR Parts 1204, 1260, 1261]

[Docket No. RM78-2 (Formerly Ex Parte No. 308)]

VALUATION OF COMMON CARRIER PIPE LINES

Order Modifying Presiding Administrative Law Judge's Order Requiring Briefs

AGENCY: Federal Energy Regulatory Commission.

ACTION: Vacation of an order of a Presiding Administrative Law Judge and ordering parties to file briefs defining the issues and suggesting additional procedural steps to be taken in this proceeding.

SUMMARY: The Commission is granting, with some modification, the joint petition of the Department of Justice, the State of Alaska and Midcontinent Petroleum Product Shippers for, inter alia, vacation of the November 11, 1977 order of the Presiding Administrative Law Judge for submission of briefs in the form of an initial decision and, instead, direction of the submission of briefs addressed to the definition of the issues and additional substantive and procedural requirements necessary for an informed rulemaking. The November 11, 1977 order of the Presiding Administrative Law Judge is vacated and parties are ordered to submit briefs defining the policy issues in connection with the proceeding that they believe the Commission should address, their position with respect to these issues and a suggested procedure for bringing this proceeding to a conclusion.

DATES: Briefs, as described above, are to be filed on or before April 3, 1978.

ADDRESS: Send briefs to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary, 202-275-4166.

SUPPLEMENTARY INFORMATION:

MARCH 13, 1978.

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, 91 Stat. 565 (August 4, 1977) and Executive Order No. 12009, 42 FR 46267 (September 15, 1977), the Federal Power Commission ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary of Energy and the Federal Energy Regulatory Commission (FERC) which, as an independent commission within the Department of Energy, was activated on October 1, 1977.[1]

The "savings provisions" of Section 705(b) of the DOE Act provide that proceedings pending before the FPC on the date the DOE Act takes effect shall not be affected and that orders shall be issued in such proceedings as if the DOE Act had not been enacted. All such proceedings shall be continued and further actions shall be taken by the appropriate component of DOE now responsible for the function under the DOE Act and regulations promulagated thereunder. The functions which are the subject of this proceeding were specifically transferred to the FERC by Section 402(a)-(1) or 402(a)-(2) of the DOE Act.

The joint regulation adopted on October 1, 1977 by the Secretary and the FERC entitled "Transfer of Proceedings to the Secretary of Energy and the FERC," 10 CFR —. *Provided,* That this proceeding would be continued before the FERC. The FERC takes action in this proceeding in accordance with the above mentioned authorities.

On December 12, 1977, the Department of Justice, the State of Alaska and

the Midcontinent Petroleum Product Shippers (Petitioners) filed a joint petition requesting that the Commission vacate the November 11, 1977 order of the Presiding Administrative Law Judge directing that final briefs be filed in this proceeding. The Petitioners further requested that the parties be directed to file briefs defining the issues and suggesting further procedures to be followed in this proceeding. The Commission herein grants Petitioners request.

On October 12, 1977, the Commission ordered the commencement and rescheduling of hearings in this case from October 18 until November 1, 1977 "in order to better determine whether further information must be gathered by the Commission or if additional issues need to be explored in this rulemaking proceeding." The hearing for purposes of cross-examination of witnesses was convened on November 1, 1977. On the final day of hearings, November 11, 1977, the Presiding Administrative Law Judge held a conference regarding briefing procedures. The Administrative Law Judge concluded the hearing by ordering briefs "in the form of a proposed initial decision" by January 16, 1978.[2]

The Petition filed December 12, 1977, calls upon the FERC to:

(1) Vacate the order of the Administrative Law Judge requiring the parties to submit final briefs on the substantive issues in this proceeding;

(2) Order the Administrative Law Judge to certify the record to the Commission;

(3) Direct the participants to file briefs addressed to the definition of the issues and additional substantive and procedural steps necessary for an informed rulemaking; and

(4) Suspend the procedural dates set by the Administrative Law Judge (January 16, 1978, for final briefs) pending resolution of this petition.

On December 29, 1977, the Association of Oil Pipe Lines (AOPL) filed a Reply in opposition to the Petition described above. In summary, the AOPL opposed the petition on grounds that a sufficient record has been compiled in the proceedings to permit filing of final briefs, as ordered by the Presiding Administrative Law Judge.

In response to the specific requests of the petition it is noted that the Administrative Law Judge, William J. O'Brien, of the Interstate Commerce Commission, who conducted the hearing in the case, did certify the record, together with fifty exhibits introduced in evidence to the FERC by a letter to the Secretary of this Commission, dated November 22, 1977, received November 25, 1977. Thus, the second item of the petition is moot, the requested action having been taken.

As to suspension of procedural dates requested by item four (4) of the petition, this has been effected by an order of the Secretary of FERC dated February 10, 1978, extending indefinitely the time for filing of briefs.

Our review of the Petition leads us to the conclusion that the order of the Administrative Law Judge for filing of final briefs was premature in light of the record now before us. Accordingly, we will grant Petitioner's third request that the Presiding Judge's November 11, 1977 order requiring final briefs be vacated and that the parties be directed to file briefs defining the issues and suggesting additional procedural steps to be taken in this proceeding.

The Commission finds. The December 12, 1977 joint petition submitted by Petitioners should be granted as hereinafter modified and ordered.

The Commission orders. (A) The November 11, 1977 order of the Presiding Administrative Law Judge establishing procedures for final briefs in this procedure is hereby vacated.

(B) On or before April 3, 1978 the parties shall submit briefs defining the policy issues in connection with this proceeding that they believe this Commission should address, their position with respect to each of these issues, and a suggested procedure for bringing this proceeding to a conclusion.

By the Commission.

KENNETH F. PLUMB,

Secretary.

—Footnotes—

[1] The "Commission" when used in the context of an action taken prior to October 1, 1977, refers to the FPC; when used otherwise, the reference is to the FERC.

[2] Tr. 1613, 1614.

¶ 31,988 Motor Gasoline Decontrol and Transition Regulation

43 F.R. 14491 (April 6, 1978).

[10 CFR Parts 210, 211, and 212]

[Docket No. EA 78-1]

MOTOR GASOLINE DECONTROL AND TRANSITION REGULATION

Analysis and Recommendations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Recommendation.

SUMMARY: This document contains the Federal Energy Regulatory Commission's recommendations to the Secretary of Energy regarding the Secretary's proposals to exempt motor gasoline from the mandatory price and allocation regulations, and special rule No. 4, a transitional gasoline program. Pursuant to section 404 of the DOE Organization Act the Commission has concurred in the proposals to exempt gasoline from the regulations and also concurred with certain recommended changes, in the Secretary's proposed transitional gasoline assignment program.

FOR FURTHER INFORMATION CONTACT:

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INTRODUCTION

By letter dated October 19, 1977, the Secretary of Energy forwarded to the Federal Energy Regulatory Commission certain amendments to the regulation under the Emergency Petroleum Allocation Act (EPAA) proposed by the Federal Energy Administration (FEA) on August 9, 1977. Included were proposals to exempt motor gasoline from the mandatory petroleum allocation regulations as well as the mandatory petroleum price regulations. In order to take effect, an exemption from either the pricing or allocation regulations must be submitted to Congress as an "energy action." Under section 402(c)(1) of the DOE Act, the Commission is required to "consider" these proposals prior to submission to Congress by the Secretary.

A separate proposal, also forwarded by the Secretary to the Commission on October 19, 1977, was "Special Rule No. 4," a transitional motor gasoline assignment program which would remain in effect for the year following the exemption of gasoline if the exemption becomes effective. Special rule No. 4 was transmitted in accordance with section 404(a) of the DOE Act, which requires the Secretary to notify the Commission of proposals to prescribe rules of general applicability in the exercise of any of the Secretary's functions transferred to him under section 301 or 306 of the DOE Act. If the Commission, in its discretion, determines that the proposed action significantly affects any functions within the jurisdiction of the Commission under inter alia section 402(c)(1), the Secretary shall immediately refer the proposal to the Commission.

At a Commission meeting on October 27, 1977, the Commission considered special rule No. 4 and determined that the proposal did significantly affect a function within the jurisdiction of the Commission, viz, the exemption, and requested referral. At that same meeting, the Commission approved a FEDERAL REGISTER notice inviting comments and scheduling a public hearing on both proposals.

The notice was published in the FEDERAL REGISTER on November 2, 1977, and established December 5, 1977, as the last day for written comments. A public hearing was scheduled and held on November 29, and 30. In addition, letters calling attention to the proceeding were sent to approximately 29 consumer organizations as well as major trade organizations which are concerned with the subject matter.

The notice in the FEDERAL REGISTER indicated that the FEA had held public hearings (six regional hearings in addition to the national hearing in Washington) and that the records of those hearings along with comments filed as a result of the FEA's August proposal would be available to the Commission. Accordingly, this summary reflects the views expressed in response to the Commission's November 2 notice as well as those expressed to FEA as a result of that Agency's August 9 proposal.

In order for a product to be exempted from the regulations the Secretary must find that the exemption is consistent with the attainment of public policy objectives in section 4(b)(1) of the EPAA. These objectives are as follows:

(A) Protection of public health (including the production of pharmaceuticals) safety and welfare (including maintenance of residential heating, such as individual homes, apartments, and similar occupied dwelling units), and the national defense;

(B) Maintenance of all public services (including facilities and services provided by municipally, cooperatively or investor owned utilities or by any State or local government or authority, and including transportation facilities and services which serve the public at large);

(C) Maintenance of agricultural operations, including farming, ranching, dairy, and fishing activities, and services directly related thereto;

(D) Preservation of an economically sound and competitive petroleum industry; including the priority needs to restore and foster competition in the producting, refining, distribution, marketing, and petrochemical sectors of such industry, and to preserve the competitive viability of independent refiners, small refiners, nonbranded independent marketers, and branded independent marketers;

(E) The allocation of suitable types, grades, and quality of crude oil to refineries in the United States to permit such refineries to operate at full capacity;

(F) Equitable distribution of crude oil, residual fuel oil, and refined petroleum products at equitable prices among all regions and areas of the United States and sectors of the petroleum industry, including independent refiners, small refiners, nonbranded independent marketers, branded independent marketers, and among all users;

(G) Allocation of residual fuel oil and refined petroleum products in such amounts and in such manner as may be necessary for the maintenance of, exploration for, and production or extraction of—

(ii) Minerals essential to the requirements of the United States, and for required transportation related thereto;

(H) Economic efficiency; and

(I) Minimization of economic distortion, inflexibility, and unnecessary interference with market mechanisms.

In addition, section 12 of the EPAA provides that any amendment submitted to Congress which proposes an exemption from the allocation regulations be accompanied by a finding that the product is no longer in short supply and the exemption would not have an adverse effect on the supply of any other oil or product. The exemption from the price regulations must be accompanied by findings that competition and market forces would provide adequate protection for the consumer and that such amendment would not result in inequitable prices for any class of user. The exemption also must be accompanied by an analysis of the potential economic impact of such amendment.

The Secretary has: (a) determined that the exemptions are consistent with the public policy objectives in § 4(B)(1) of the EPAA (supra), (b) found that motor gasoline is no longer in short supply and that exempting it from the pricing and allocation regulations would not have an adverse effect on the supply of oil or other refined products, (c) found that competition and market forces will provide adequate protection for the consumer and the exemption will not result in inequitable prices for any class of user, and (d) provided an analysis of the potential economic impact of the proposed exemptions. It is these issues which the Commission must now consider.

Although a representative of the Secretary made an oral presentation at the hearing on November 29, the basis for the Secretary's determinations and findings is contained in a document entitled "Final Report—Findings and Views Concerning the Exemption of Motor Gasoline from the Mandatory Petroleum Association and Price Regulations, September 1977." This document was made available to interested persons in this proceeding. An earlier draft was made available to the public at the time of the FEA proposal. At that time it was FEA's "Preliminary Findings." Subsequent to FEA's review of the comments and oral statements in that Agency's proceedings, it was revised as a final report.

In addition to a general discussion of the motor gasoline industry and history of price controls, supply and demand trends, etc., the final report contains the technical information which the Secretary believes supports the determination and findings which must accompany the exemption.

GASOLINE SUPPLY AND DEMAND

FEA ANALYSIS

Chapter IV of the final report contains an analysis of supply and demand projections through the year 1979. Since so many of the issues depend on the availability of motor gasoline, this chapter deserves special attention. The FEA analysis indicates that the total supply of motor gasoline will be barely adequate to meet the total projected demand for 1978 and 1979 on an annual basis. That analysis assumed no waiver to the lead phasedown schedule by the Environmental Protection Agency and that the use of MMT (an octane booster) would be banned. Chapter IV also gives the results of a survey of 17 large refiners representing production of 84.1 and 78.4 percent, respectively, of domestic unleaded and leaded gasoline. The aggregation of the estimates of the refiners indicated that supply will meet demand "comfortably in 1978" and "marginally in 1979 if the EPA approves such requests it has received for waivers from its lead phasedown schedule." The refiners' forecast indicated that if EPA did not grant the waivers a shortfall of about 200,000 barrels per day in 1979 could develop.

At the public hearing the representative of the Environmental Protection Agency indicated that the Agency has requests from 52 refiners for suspension of the regulations with respect to 109 refineries. Indicating that they had already granted a few of the requests, the EPA spokesman went on to state, "We anticipate granting the suspensions for the majority of the remaining requests that are still pending." Again, the FEA's own "worst case analysis" showed supplies to be tight but adequate, even without such waivers, and the refiners' own aggregated estimates indicated that supply would marginally meet demand, if the EPA granted the waivers.

More specifically, the supply problem in 1979 is identified as primarily one of domestic refiners difficulty in producing sufficient quantities of high octane gasoline without the use of lead or other additives to increase octane ratings. The report points out that this situation, to the extent that it is a problem, will be a problem with or without controls. It further indicates that if a supply shortage does materialize in 1979 the Federal Government will be faced with the choice of allowing price increases which would restrain demand, or to suffer the shortfall, restraining prices by price controls, and distributing the available gasoline by allocation controls. In this regard it should be noted that any product which is exempted from the regulations under section 4(a) of the EPAA is subject to the reimposition of price and allocation controls if the Secretary determines that the reimposition of controls is necessary to attain the objectives in § 4(b)(1) [quoted infra].

None of the commenters presented any independent analysis of the supply/demand situation. Some companies indicated they did have such projections, but their own analysis did not indicate that supply would be insufficient to meet demands through 1979. Also, to the extent that individual major refiners were asked, they indicated that their own projections led to the conclusion that they would be able to satisfy their customers' demands for both leaded and unleaded gasoline, through 1979, taking into account their projected growth.

SUPPLY AND OUTLOOK FOR PRICES

The final report on the proposed exemption, summarizes the Secretary's analysis of the outlook: "FEA forecasts an adequate supply situation in 1979 despite a refiners' survey indicating possible shortfall in 1979 and FEA concludes that the maintenance of allocation and price controls is not warranted." These conclusions are based upon FEA's analysis of the gasoline market. Their analysis focused on four topics: (1) a forecast of oil product demands for 1977-79, (2) refining capacity and oil supply, (3) pressures on costs and prices, and (4) trends that may affect competition.

DOE staff continually reviews developments in the petroleum industry and periodically checks with the Council of Economic Advisers to determine if revisions in the economic outlook make it necessary to revise their projections. Actual behav-

ior of the petroleum industry and the economy subsequent to the publication of the final report have not lead to any significant changes in projections from the model used by FEA and DOE in analyzing the outlook for the oil markets. Analysts studying a subject as complex as the gasoline market, however, rarely if ever reach unanimous conclusions on all details and the projections cannot be proven. It is, therefore, not surprising that some analysts do not accept the FEA conclusions.

Two commenters on the final report presented points of view significantly different from FEA. This analysis therefore includes evaluation of points made in comments by Congressmen Floyd J. Fithian and Andrew Maguire. It also includes a review of points made by William H. Bode, Attorney for Nelson Oil Co. Mr. Bode presented questions for DOE and the DOE's answers to those questions are also included as part of the total package of information to be considered.

DEMAND FOR MOTOR GASOLINE

Domestic demand for gasoline and all products was prepared by FEA analysts using an econometric model and DOE provided backup details on its use of macroeconomic variables. The demand forecast is predicated on inputs showing expected development in real GNP, consumer prices, wholesale prices, manufacturing activity, real national income, wholesale prices for fuels, defense purchases, and production of chemicals. The concept and the input factors, at the very least, offer a plausible system for projecting the oil market under normal circumstances. The validity of the projection is, of course, also dependent on the accuracy of predictions of input factors.

The FEA projections were made with the realization that new developments would not be reflected in the output from their model. The projections were therefore revised to reflect the impact of the crude oil equalization tax (COET), the increased use of diesel engines in cars and trucks, and expected improvements in efficiency of gasoline engines.

The COET impact on product demand would reflect the market response to price changes caused by the tax. This impact has been developed by the DOE model and like the impact of most oil price changes, is small in the short run.

The impact of increased use of diesel engines in vehicles of the type that have usually been gasoline powered in the past was studied in some depth by FEA. Their analysis includes review of manufacturers' estimates of the market and the production plans as well as consultant studies and independent FEA analysis. Indications are that the sales are limited by the supply of vehicles, so the projections should be quite accurate.

The economy in gasoline engines is more difficult to predict, but DOE staff has been working with consultants and manufacturers to keep current on developments. The mix of sales and the actual miles per gallon of the vehicles are variables that are most difficult to predict, but the analysis of DOE seems to consider all possibilities. The FEA data probably underestimate the effect of gasoline economy unless there are unforeseen developments that would require a new evaluation of the entire market for oil products.

Demand for unleaded and leaded gasoline was calculated as a percent of the total gasoline demand. The percentages for each type were developed by EPA who based their calculations on a study of the motor vehicle fleet, new sales and requirements for new cars. While this calculation is exogenous to the model used for the other projections, it represents a calculation that is consistent with the concepts used. It is not likely that a change in the model structure to provide separate market estimates for each type of gasoline would provide significantly different results.

The gasoline demand projections in the report have been reviewed and analyzed. DOE staff has provided FERC staff with descriptions of the rationale and workpapers to help evaluate their published analysis. Our evaluation of the FEA/DOE development of the demand outlook is that it represents careful analytical work with a reasonable rationale for all figures shown. Alternate methods of projections could be developed, but there is no reason why the results from any other method would be inherently better than those used by the FEA.

As noted above, the FEA surveyed 17 large refiners on the adequacy of supplies of gasoline. At the same time, the FEA asked for their projections of the total market demand for leaded and unleaded gasoline. Fourteen of the 17 companies[1] provided such projections:

1978

Unleaded	Leaded	Total
3,125	3,980	7,106
2,570	4,580	7,150
2,273	4,909	7,182
2,660	4,550	7,200
2,500	4,700	7,200
2,475	4,770	7,245
3,200	4,050	7,250
2,300	5,950	7,250
2,466	4,829	7,295
2,780	4,550	7,330
2,714	4,621	7,336
2,530	4,805	7,335
2,647	4,706	7,353
2,660	4,720	7,380
[2]12,635	[2]14,623	[2]17,258
[2]2,600	[2]4,600	[2]7,200

1979

Unleaded	Leaded	Total
3,576	3,576	7,145
3,150	4,010	7,160
2,877	4,296	7,173
3,350	3,950	7,300
3,300	4,000	7,300
2,935	4,320	7,256
3,950	3,350	7,300
2,800	4,650	7,450
3,108	4,292	7,400
3,310	4,050	7,360
3,200	4,150	7,410
3,130	4,330	7,460
3,264	4,179	7,463
3,399	4,135	7,525
[2]3,244	[2]14,092	[2]17,336
[2]3,200	[2]4,200	[2]7,400

[1] Average
[2] FEA

The forecasters were not identified by FEA. They are listed by magnitude of the 1978 volume of total unleaded and leaded gasoline. The data represent forecasts prepared within the private sector, so no work sheets or back up documents are available. The arithmetic average of the forecasts is very close to the FEA projection and the range of forecasts is within about two percent of average in 1978, 2 ½ percent in 1979; these statistics tend to give confidence to the FEA total figures. The averages are also close to the FEA figures for both the leaded and unleaded shares of the market, but confidence in these figures cannot be as great. The range of individual estimates of unleaded gasoline runs from 14 percent below the average to 21 percent above the average in each year; the higher level of demand could cause problems. The leaded gasoline share also shows a wide range but this is not as serious since unleaded gasoline can be used in cars designed to use leaded gasoline.

One added note on demand for gasoline. Mr. Bode, Nelson Oil Co.'s attorney, pointed out that the Department of Transportation preliminary figures show higher demand for gasoline than the FEA. Department of Transportation data bases its data on state tax collections and the Bureau of Mines/Department of Energy data are based on supply disappearances (refinery output + gasoline plant output + exports ± stock changes = demand). The DOT data show larger demand in prior years than does Bureau of Mines but the trends are about the same; DOT figures quoted by Mr. Bode show the first 9 months 1977 gasoline use up 3.1 percent compared to 1976 and the FEA shows 3.2 percent growth in 1977. These different figures have been published for years; no complete ready explanation is available from either agency although DOT preliminary data probably include some fuels other than gasoline. DOT data do not balance supply with demand, a key item in this analysis, so it is appropriate that the Bureau of Mines system is used.

REFINED PRODUCT SUPPLY FORECASTS

FEA projected gasoline supply based on the outlook for refinery capacity (to process crude petroleum), catalytic reformer capacity, crude oil supply, imports and an evaluation of the impact of restrictions on the use of MMT (a manganese compound that can be used to improve octane ratings).

Refinery capacity forecasts were developed from publicly announced plans of refiners. Refinery building plans are not normally trade secrets (although the details of the plans may be); it is difficult to keep information on land purchases, contracts with construction firms and zoning and building permits from public knowledge. Figures on future capacity are usually known fairly accurately for the short range future; the trade press, the source for FEA figures, can provide good information for the forecast period in the FEA's final report.

The FEA outlook on refinery yields cannot be considered as accurate as their figures on capacity. Their analysis of refining equipment was limited to crude charging capacity and catalytic reforming capacity while there are other types of downstream equipment[2] that can affect the yields. The FEA's method of determining the combination of refinery production, imports and natural gas liquids was designed to minimize imports. A minimum level of product imports minimizes payments for oil and reduces costs to consumers. The Final Report indicates a margin or error on the supply estimate of 100 thousand barrels daily, about 1.5 percent, which seems small; the potential for larger output of gasoline, particularly, seems understated as shown in the following tabulation of data from the FEA Final Report:

CRUDE OIL INPUTS AND GASOLINE YIELDS
[Thousand barrels per day]

	1976	1977	1978	1979
Crude oil input*	13,416.0	14,000.0	15,200.0	15,800.0
Increments (vs. 1976)	.....	+1,184.0	+1,784.0	+2,384.0
Gasoline yield*	6,121.0	6,300.0	6,300.0	6,500.0
Increment (vs. 1976)	.....	179.0	179.0	379.0
Percent gasoline yield*	45.6	43.4	41.4	41.1
Percent gasoline yield on incremental crude oil input	....	15.1	10.0	15.9

* Source: FEA Final Report, table IV-5.

The percent gasoline yield on the incremental crude oil input after 1976 seems inconsistent with the history of crude processing in this country and, even without major increases in catalytic reforming capacity, it should be possible to produce more gasoline.

A more severe restriction may be the quality of the gasoline. Gasoline from straight run distillation of crude oil and from cracking and coking operations do not have octane ratings as high as output from reforming operations and from some natural gas liquid fractions. The blending of these fractions to provide an adequate octane level will be less of a problem with the relaxation of EPA restrictions on use of lead in gasoline. The analysis of the gasoline quality was developed on the assumption that the average octane level of the gasoline supply will remain at about the present level. The assumption was adopted after a review of projected refinery building programs which showed that the mix of refinery equipment would not change significantly.

The refinery utilization factor as presented in the final report may also present a problem. The refinery percent utilization is shown to increase from 86.9 percent in 1977 to 88.3 percent in 1978 and 91.0 in 1979. The 91 percent utilization factor in 1979 is the highest since 1966 when runs were 91.8 percent of capacity. (In 1967, 1968 and 1969 refineries ran between 90 and 91 percent of capacity.) As noted above, the supply figures were developed to show maximum utilization of domestic refineries. In 1978 the data shows no increase from 1977 import levels but in 1979 even with operations at 91 percent of capacity additional imports will be required.

The U.S. refining industry should be able to operate at 91 percent of crude oil processing capacity, although product requirements may present problems. Refiners can change their product yields and can operate at high utilization factors but there are some physical limits on their operating options. The projected output from the refineries shows a decrease in the yield of gasoline, the product for which most refineries have been designed. This would suggest that the refinery options may be restricted. However, much of our gasoline is produced by downstream units which convert distillate and residual fuel oil to gasoline. Thus, the decline in gasoline yields may make it possible for refineries to make better use of their straight distillation facilities and to operate at high percentages of refinery utilization.

Catalytic reforming capacity was studied by FEA and they note that the supply of high octane output from reformers may be a limiting factor in gasoline supply. The U.S. refinery industry is said to have some alternative options to ameliorate the problems of gasoline supply. FEA lists: Emergency debot-

tlenecking; crude intake changes; yield changes (although they previously noted that the catalytic reformer capacity may restrict the ability to increase gasoline production); increases in processing severity; deferral of planned maintenance or renovations; and changes in feedstock. The full potential of these options is not explored.

FEA also checked with 17 major refiners on the outlook for supply of leaded and unleaded gasoline. The data from these 17 companies show that refiners expect to be able to supply adequate unleaded gasoline but that they see a possible shortfall in the leaded gasoline in 1979. With the waiver of EPA lead phasedown, the refiners may have the option of adding lead to excess unleaded gasoline.[3]

The data presented seem to indicate that the supply of gasoline from U.S. refineries is understated by FEA although quality constraints may make the outlook less favorable than seen here. Any increase in gasoline output at U.S. refineries would require an equal or larger decrease in the output of other petroleum products. For a net importer of crude oil and petroleum products, the balancing factor must be imports and the imports must be determined by the availability abroad and needs in this country.

Foreign refining capacity shown by FEA indicates a surplus capacity that would not be taxed to meet import needs much larger than those projected in the final report. Quality might be a problem. FEA indicates foreign refineries may not be able to produce more gasoline without also producing six times as much fuel oil although foreign refineries are running considerably below capacity. The present percent yields in European refineries show that these refineries produce 3-barrels of fuel oil per barrel of gasoline, and there is probably some flexibility in their yields. Foreign refineries may even now be producing an oversupply of gasoline; some of the commenters suggest that gasoline is available outside of the United States.

In the Final Report, natural gas liquids (NGL) are held at a constant level during the forecast period. NGL supply will tend to depend upon production of natural gas which has been declining for several years. Preliminary 1977 data suggest that the decline may have been halted, but it may be unduly optimistic to project no further decline in 1978 and 1979. Any reduction in the supply of NGL would, however, probably be small and not a significant factor in the overall gasoline supply balance.

With net U.S. imports, probably flexibility of yields at both domestic and foreign refineries and the possibility of changing the import levels of all products, it should be possible to meet gasoline needs in this country without causing shortages in other products. In time, new facilities can be built to provide ample capacity to supply all needs.

The FEA has analyzed foreign crude oil supply and determined that it is adequate for the period covered. The potential world-wide crude shortage projected by the CIA for the 1980's is not covered in the Final Report.

Aside from the quality problems noted above, there may be seasonal problems. FEA estimates peak period (June–August) gasoline to exceed annual average demand by 500 thousand barrels daily in 1978 and 400 thousand barrels daily in 1979. The suppliers in 1977 managed to supply an extra 400,000 barrels daily in the summer. The excess summer demand in 1978 could be supplied by a drawdown of stocks of 46 million barrels from the 240 million barrels expected June 1 stocks. Such a drawdown is considered excessive by FEA, but some imports may be stored abroad in the first part of the year for delivery in the peak period. Seasonal problems will also depend on the vehicle use patterns that develop. Under any circumstances it will be necessary for DOE to monitor the gasoline supplies particularly during the peak driving periods.

It should be possible to manage the supplies of gasoline to meet the demand for the next two years if FEA evaluation of the world-wide capacity to produce and refine crude oil are accurate. In fact, the data that FEA presents seem to indicate a more favorable supply position than they show in the Final Report.

PRICING FACTORS

FEA has concluded that "competition and market forces are adequate to protect consumers" from inequitable price increases. Refiners have been recording un-

recovered costs in "banks" when they could not charge the full ceiling price. Refiners are allowed to pass through increases in crude and other purchased raw material costs and certain non-product price increases. The past record would seem to indicate that the price restrictions do not inhibit the ability of the refiners to make profits. Even with prices below ceilings, output has increased and the domestic petroleum industry since 1971 has increased its percent return on equity. Gasoline prices at the pump have risen and the markup of gasoline price over crude costs has risen each year since 1972. From the data available, it would seem that price regulations have not saved the consumer from increasing prices nor have they restricted the industry's ability to make a reasonable profit.

Congressmen Fithian and Maguire point out that during the period of regulation, "there has never been a major refiner audit," and "there are no real accounting data . . . which might indicate exactly what gasoline costs." Until better data are available it will not be possible to analyze the benefits of price controls and allay fears that refiners have accrued excess profits during controls.

Without DOE audits of oil refiners, there can be no assurance that there has been proper accounting for the product and non-product costs that have been added to the price ceilings. If refiners have overcharged their customers some repayment may be in order. The means of repaying customers for any overcharges and the method to flow-through any portion that would need to be passed on to resale customers and ultimate consumers has, as far as we know, not been established. A task force in July 1977 recommended to FEA that procedures for necessary remedial action on overcharges should be established. Development of such a program would take some time, as will an auditing program. The task force recommended an auditing program that will take 18-24 months. Any repayments for overcharges will clearly present a problem whether or not gasoline is exempted from price control.

One reason for an ample gasoline supply that tends to develop competition for the motorists' business may be that the refiners desire to prove that price controls are not needed. The ability of the government to reimpose controls may provide the same incentive since a reimposition of controls might be implemented more severely.

FEA forsees a continuing increase in crude oil costs with no end to OPEC price escalation during the next two years and with the crude oil equalization tax. These increases would result in comparable increases in ceiling prices for products.

The construction of additional refining facilities could also increase the cost of oil products. Refiners generally make no secret of their desires for higher prices (these are usually expressed as hopes more than expectations). They also indicate that investments in additional facilities will not occur when prices are under control. FEA concluded that "an increase in the price of motor gasoline will probably be necessary to cover capital costs for expansions in refinery capacity." Thus, there may be some increases in gasoline prices to cover the cost of a refinery expansion program if price controls are lifted and if the market will support a price rise.

The rising cost of incremental supplies of gasoline show that in the gasoline market, as with natural gas and electricity, conservation is cost effective. The consumer who reduces his consumption not only reduces his own costs but also reduces the need for high cost additional supplies and thereby helps keep costs down for everybody. Neither control nor exemption provides a means to reward the conserver.

Although FEA's findings include the statement that "competition and market forces should be adequate to protect consumers as long as motor gasoline supplies remain adequate," the record of gasoline "banks" during the past summer indicates pressures for prices to rise above maximum allowable price. The operation of banks was summarized by the Department of Justice:

Current price regulations for gasoline allow a refiner to charge a price equal to its May 1973 price plus the increase in its product costs and certain allowed non-product costs. If a refiner is constrained by market forces from increasing its price to the allowable maximum, then it may bank the costs which it was allowed but unable to recoup. At a later date, if

market forces permit a price above the ceiling, the refiner may increase its price above the ceiling by an amount such that its increased revenues for a given month are no more than 10 percent of its total bank. The bank is then drawn down by an amount equal to revenues over and above the legal ceiling price.

Costs are banked for all products still under regulation. Refiners can reallocate banked costs from other products still under controls to motor gasoline. The maximum price charged by a refiner is thus the May 1973 base price plus allowed cost pass-throughs plus 10 percent of the cost banks for all regulated products.[4]

DOE data on "unrecouped Costs for Refined Products for 30 Largest Refiners" show that refiners' banks for gasoline on a net basis were drawn down each month from April through August 1977 with a total drawdown of 28 percent; during the same period total banks for all products were down by 11 percent. These figures show that there were upward pressures on gasoline prices during the past summer's peak driving season and that during the four month period more revenue from refiners' sales of gasoline came from transactions at prices above the ceilings than below. August 1977 banks, however, were higher than they had been the previous year indicating that cumulative sales for the twelve months had generally been below ceilings. In September DOE reported 16 reductions in gasoline price by refiners compared to 12 increases; in August there had been 19 increases and 13 reductions. With price reduction in the fall, banks may again increase.

FEA's analysis of margins for refining, distributing and retailing points out that profit margins on gasoline have not risen as rapidly as inflation; inflation was measured by the Consumer Price Index (CPI). Their analysis also points out that this has not limited the profitability of the gasoline business. Comments before the FERC panel indicate clearly that refiners, distributors and retailers all want to see their profit margins increase. Any increase in prices, however, will not come in response to changes in the CPI; price changes will reflect market conditions in a competitive market, or administrative decisions in a monopoly or oligopoly situation.

Prices of gasoline are expected to increase. FEA analysis shows no clear indications that motor gasoline prices will rise much more rapidly if exempted and estimates a one cent increase compared to controlled prices. Congressmen Fithian and Maguire, on the other hand conclude that the increase would be 3.3¢ per gallon plus the full amount of any increases in the price of OPEC oil.

Price changes for gasoline will be a function of crude oil costs, other raw material costs, operating costs and competitive market conditions. Under controls, costs will determine ceiling prices and market conditions may force prices below ceilings. Price under exemption would be expected to be the same as or higher than prices under control, if other things remain equal. As long as supplies are adequate, prices should not show much change, although summer prices may show a more pronounced peak than they do now. According to Jack Blum of the Independent Gasoline Marketers Council, "While surplus in the product market is two percent oversupply, terrible shortage is two percent undersupply. So it doesn't take much at all to trip the balance to a situation being competitive or totally non-competitive."

Wider swings in prices would seem probable under decontrol and geographic differences might become more pronounced. COET would tend to direct excess revenues to the U.S. Treasury, but would not eliminate all possibility of excess profits. Adequacy of supply will be key in determining how prices behave under exemption. The audit program should increase our knowledge about the accounting methods of the refiners and might result in setting ceilings lower than the present market prices. The method of handling any excess is not discussed by FEA or by Congressmen Fithian and Maguire who suggest that there may have been overcharges under the control program. The effectiveness of refund procedures are not known. A repayment to the Treasury might be as equitable as any other refund option, and would appear to be more effective than delaying decontrol if decontrol is determined to be proper at this time.

MARKET STRUCTURE AND COMPETITION

Gasoline moves through various channels from the refiner or importer to the ultimate consumer. FEA has identified nine categories of wholesalers and distributors and shows the percent market shares for the six who deal with ultimate consumers. There is competition of various degrees of intensity within each of these groups and there is competition among the groups as they strive to increase their sales so they may increase their profits.

FEA data on market shares show that between 1972 and 1976 when gasoline sales increased by 11 percent, the refiners' direct distribution actually declined as more business went through jobbers. The branded lessee dealers felt the largest part of this loss while refiner operated stations sales increased by two-thirds during this period. Some jobbers and retailers expressed a fear that this trend represents an anti-competitive development rather than a trend toward improvement in the distribution system. No thorough study of the causes of these trends was presented nor was there any evaluation of the likelihood of their continuation.

Under any circumstances it will be necessary for the DOE to monitor developments in the gasoline distribution system. With the amount of money involved in these operations there can be strong temptation for some parties to plan operations designed to increase market control and profit levels without providing improved service to consumers. Developments under controls indicate that some classes of gasoline marketers have not fared well. The trend toward fewer gasoline stations, each handling a larger volume probably will continue as long as the gasoline buying public demonstrates a preference for this type of service. To the extent that the gasoline market will decline as specified in the NEP and as indicated in some comments before the FERC panel it may be inevitable that some dealers will be forced out of business, and DOE surveillance can assure dealers that any attrition is nondiscriminatory.

OTHER FACTORS

IMPACT ON OTHER PRODUCTS

Exemption of motor gasoline can impact adversely on other petroleum products in three ways: (1) Decrease availability, (2) increase prices to consumers, (3) impair quality.

A decrease in the availability of other products would come if refineries increased their yield of gasoline. FEA shows that U.S. gasoline yields are expected to decline under exemption; if this is true, domestic supplies of other oil products should not be adversely affected. If gasoline prices rise and gasoline sales decline (in response to higher prices) U.S. gasoline yields may decline even faster than shown in the FEA studies. Thus, supplies of other products will benefit. Supplies from foreign sources to supplement U.S. refining output should not be impaired by exemptions. Foreign refineries are not running at capacity and they may be faced with an oversupply of fuel oil during the near term future. Thus maintaining an adequate supply of products other than gasoline does not seem to pose a problem.

A minimal, if any, impact of gasoline exemption on the price of other products seems likely. If market conditions limit prices to the same level as under control, the same price pressures would impact on other products. If gasoline prices rise there would be less necessity for refineries to recoup their costs from other products (although it is not likely that any increase in gasoline price would be large enough to result in a decrease in price for other products.) Competition between gasoline and diesel oil or LP gas for the motor fuel market is not expected to have a major impact on the prices of the products because the existing vehicle fleet cannot switch from one fuel to another.

If gasoline yields increase, and output of other products at U.S. refineries decreases, a larger percent of higher priced imports of other products might force prices up. However, as pointed out in our analysis of supply (supra), FEA looks for a decrease in gasoline yields and thus there would seem to be no reason to look for any impact on prices of other products at this time.

The quality of other products could be affected if there was a change in the feedstock or a change in the operations at refineries. New equipment or modification to existing equipment could also affect product quality. The FEA analysis of the outlook for new equipment does not suggest any change in the quality of product. Nor have any commentators suggested any change in quality.

Supply, prices, and quality of other products may change during the next two years, but there is no indication that any such changes will be a result of exemption of motor gasoline from price control.

IMPACT OF EXEMPTION ON THE ECONOMY

The impact on the economy from the exemption of motor gasoline from price controls will depend in large part on the magnitude of any price change that follows exemption. FEA's analysis based on Data Resources, Inc. (DRI), quarterly econometric model of the U.S. economy shows that a 1 cent per gallon increase would have only a "quite small" effect, and a 10 cent per gallon increase in price would have a significant effect. The FEA report points out that "historically gasoline demand has been relatively unresponsive to short-term changes in gasoline prices": Their short term model shows an elasticity of 0.2 but they indicate 0.1 elasticity may also be possible.

The gasoline market in the United States of 7.2 million barrels a day is equivalent to 110 billion gallons per year. A 1 cent change per gallon would therefore amount to $1 billion and a 10 cent change to about $11 billion. Changes in gasoline prices of course, have a direct and immediate effort on the consumer price index and the wholesale price index. Moreover, when consumers pay more for gasoline they will have fewer dollars for other purchases or investments. It is the consumer's decision of where to cut expenditures or reduce savings that will probably have the biggest impact on the economy.

The FEA analysis uses an econometric model and assumes a predetermined behaviour by consumers; the reliability of the conclusions depends upon the assumptions that are built into the model.

If consumers as a group view the changes in gasoline prices as being permanent or long lasting there may be some changes in behavior patterns. We have seen in the recent past a notable interest in the demand for small cars and energy efficient cars. U.S. manufacturers are producing more small cars to meet this market and also producing diesel-engined passenger vehicles for passenger use, an option that was not considered several years ago. As manufacturers respond to their view of consumer demand supplies and marketing pressures will change.

Several possible variances to the FEA figures therefore suggest, themselves:

1. Use of small automobiles in excess of FEA expectations.

2. Increased reliance on public transportation.

3. A decreased use of motor vehicle for recreational purposes.

Any of these developments, all of which are energy efficient, would result in different conclusions than those shown by the FEA.

In the past the small economy car was largely an imported car. Today the United States is manufacturing more of these. As the dollar falls against foreign currency the American products become more viable. An increased demand for American small cars could lead to expansion for the State of Michigan rather than the decline in economic activity shown by the FEA.

An increase in the use of public transit facilities would probably require improved service and more busses and subway cars. To the extent that public authorities pursue this option, and provide good reliable service without excess fare increases, we may see a decreasing reliance on automobiles and an increased use of public transit in urban areas. This development could also decrease the demand for automobiles with the adverse impact on Michigan projected by FEA. There would, however, be an increased demand for busses and other public transit vehicles which could more than offset the decline in private cars, at least in the short run.

A decrease in the use of vehicles for recreation would have the impact of decreasing the demand for gasoline and for automobiles without any significant in-

crease in demand for any other product except perhaps bicycles.

Each of these behavior patterns could improve the nation's energy efficiency. American consumers by any of these choices would reduce the demand for gasoline thereby decreasing our need for imports of crude oil and products. Any reduction in oil imports will improve our balance of payments. The impact of improved balance of payments could have a beneficial impact on the economy that might more than offset the adverse effect of the increased gasoline price.

The economic impact of the increase in gasoline price will be influenced not only by consumer decisions but also will be affected by state, federal and local government decisions concerning the use of the motor vehicles.

PUBLIC POLICY OBJECTIVES

In addition to the analysis of the market behavior, section 4(b)(1) of the EPAA requires, as noted above, consideration of: (A) Public health, (B) public services, (C) agriculture, (D) petroleum industry competition, (E) crude oil allocation, (F) oil distribution, (G) mining, (H) economic efficiency, and (I) minimizing economic distortions.

In the FEA report and the comments, most attention was given to section 4(b)(1)(D) concerning the preservation of an economically sound and competitive petroleum industry. A large portion of the written and oral comments to the FERC and to the FEA addresses this matter. Frequently this topic was expanded to relate to matters of equitable distribution of oil products, efficiency and minimizing economic distortions in the oil industry. These problems were considered by FEA and the proposed special rule No. 4 was designed to avoid the potential adverse impact of instantaneous complete removal of controls.

The matters of public health, public service, agriculture, crude oil distribution, and mining were not specifically addressed by FEA and only a few of the commentors suggested they need to be considered. These "minor" (In terms of space devoted to them in the record) considerations are discussed here before the review of the more controversial policies of special rule No. 4.

Section 4(b)(1) (A) relates to the protection of public health, safety, and welfare and (B) to maintenance of all public services. FEA did not cover these items; the States of Vermont, New Hampshire, and Maine, however, expressed concern that public service, most especially ambulance service, could be adversely affected. State set-asides were suggested as a means of avoiding serious consequences that could occur.

Several letters to the FERC and FEA mentioned socioeconomic problems connected with higher gasoline prices. These letters, however, did not indicate the significance of gasoline prices in the overall problems. Undoubtedly there are situations that will be adversely affected by an increase of 1 cent per gallon but there is no indication that gasoline prices are the best means to alleviate the socioeconomic problems throughout the country.

Section 4(b)(1)(C) relates to the maintenance of agricultural operations. This, again, was not specifically analyzed by FEA. One commentor, Western Farms Association of Seattle, Wash., expressed the fear that under exemption the supplier will pull out of the low-density markets where their members operate and that gasoline prices to them will rise as compared to the rest of the Nation. Since farm product prices are not always immediately responsive to farmers' costs, the Western Farmers Association fears that its members will suffer financial losses and/or be forced out of business. They therefore recommend against exception at this time. The National Council of Farmers Cooperatives, on the other hand, sees no major problems that will impact on farmers because of the exemptions. The Western Farmers Association problems are similar to those raised by some retailers. Generally the retailers advocated protection by modification to special rule No. 4.

Allocation of crude oil (section 4(b)(1)(E) and mining, (section 4(b)(1)(A)) were not mentioned in the record in this Docket. FERC staff review of the proposed exemption indicates that the public interest determination will not hinge on these factors.

COMMENTS ON THE EXEMPTIONS

Although there are two proposals, one to exempt motor gasoline from the mandatory petroleum allocation regulations and the other to exempt that product from the mandatory petroleum price regulations, the commentors generally treated them as a single proposal to decontrol motor gasoline from government regulation. And the few commentors who treated the two proposals separately appear to concur that there is an interrelationship between allocation and price and, as a result, the proposed exemptions should be adopted or rejected together.

The comments and oral presentations to the FEA and DOE largely favor exempting motor gasoline from government regulation. And only a few in the industry flatly oppose it. As is discussed below, the level of support for the exemptions varies according to the possible and/or probable adverse effects of decontrol upon the particular interests represented by the speaker.

Those commentors who address the matter acknowledge almost universally that government controls were essential to their business survival during the oil embargo which was imposed in October 1973. But with the passage of time, and the demonstrated adequacy of motor gasoline supplies subsequent to the end of the embargo, most commentors agree for a variety of reasons that the existing controls have outlived their usefulness and should, therefore, be removed. Others, however, favor the continuation of controls because of their apprehensions of adverse effects on their own operations. But, as indicated, most commentors would remove controls and would mitigate such adverse effects through one or more transitional protections, such as special rule No. 4. Of those who commented on the subject, a strong majority appears to advocate the development of standby controls which can be implemented quickly in the event of another gasoline shortage. Special rule No. 4 and other protective measures are discussed below.

Within the motor gasoline industry, the refiners favor the termination of existing controls. They contend that the regulations do not allow an adequate return on capital investments or processing technique improvements and do not permit them to make new marketing commitments. They claim, therefore, that existing controls operate as a disincentive to capital investment and that, as demand increases, controls will lead to future shortages of petroleum products. And they claim that existing controls are burdensome and result in unnecessary paperwork, a criticism in which the wholesalers and retailers join. In fact much of the support for the exemptions is the result of frustration with the existing regulations. As one retailer group said, "We would prefer to take our chances with whatever remains of a free market than with the existing system of controls."

Two groups of terminal operators, who occupy the first step in the distribution of motor gasoline, favor decontrol. While one of the groups (whose members are primarily fuel oil distributors) believes that supplies of motor gasoline will remain adequate and favors decontrol as proposed, the other group appears to be apprehensive of a shortfall in 1979 and states that it favors exemption only if independent terminal operators are afforded an opportunity to import competitively priced gasoline.

At the wholesale distribution level, most jobbers and consignees are in general agreement that controls should be ended. They cite figures indicating that during the period of controls numerous retailer-customers have gone out of business, that refiners have increased their direct retail gallonage and bypassed them, and that independent marketer margins are at an all-time low. Other wholesalers, however, are apprehensive of an immediate loss of supplies and of trends toward the elimination of commission marketers and, therefore, they oppose decontrol until the enactment of the Petroleum Marketing Practices Act (H.R. 130, commonly known as the dealer day in court bill).

At the retail distribution level there is a general concurrence that motor gasoline should be exempted. But the level of support and arguments made for decontrol depend to a great extent upon the particular situations of the retailers who are speaking. And the comments range from strong support of the exemption, to support with added protections, to support only with the adoption of speci-

fied protections, some of which would appear to frustrate a return of the competitive marketplace which, in turn, is generally believed to be the major benefit of exemption. Some retailers have written to the FEA and the Commission opposing any change from existing controls.

Branded lessee dealers ordinarily have a single source of supply and, conversely, are not free to shop for surplus product at a price. The vast majority of their spokesmen seem to consider the Petroleum Marketing Practices Act essential for the survival of most of these dealers. They cite FEA figures showing that their number has declined 34.8 percent from 112,000 in the first quarter of 1972, to 73,000 in the fourth quarter of 1976. Such retailers claim that they are caught in a market squeeze for survival between their increased operating costs, particularly their increased rents by their supplier-lessors, and the cutthroat price competition of their nonbranded and private branded competitors who sometimes sell products at retail at prices which are at or below the wholesale prices at which the branded lessee dealers purchase the same product.

A majority of wholesalers and retailers appear to agree that in periods of adequate supply, as have been experienced since the lifting of the 1973 embargo, the allocation regulations have been more harmful than beneficial. Suppliers are required by the regulations to reserve base period (1972) allocation volumes for customers who they know, because of changed conditions during the 4 years of control, will not lift those volumes. As a result suppliers cannot and, therefore, will not enter into new and/or expanded supplier-customer relationships. And as a further result, both wholesalers and retailers contend that the allocation regulations stifle competition.

A number of persons and firms at all levels of the motor gasoline distribution system see themselves as being hurt, or as possibly being hurt, by the removal of controls. The reasons vary, but a major factor seems to be that under controls the motor gasoline industry has not responded as rapidly as it might have to changing market conditions. Accordingly, there is considerable apprehension within most segments of the industry that when the thaw in controls begins, numerous changes will come about within a relatively short period of time. This may be generally disruptive of the marketplace and could be financially harmful to some in the industry. But a large part of the industry has expressed its general disenchantment with controls and its preference to take the risks which are inherent in returning to an unregulated market.

Special Rule No. 4

TRANSITIONAL PERIOD PROTECTION

FEA did not expect supply dislocations to occur as a result of motor gasoline exemption but did design special rule No. 4 as a safeguard against unforeseen supply dislocations. This proposal was not covered in the FEA analysis, but was the subject of considerable comment.

The comments on special rule No. 4 point up the main concerns that are felt about the exemption proposal. Price controls and allocation of gasoline since 1974 have restricted and possibly distorted normal market development even though gasoline supplies have generally been adequate. As each marketer of gasoline has tried to maximize his profits, the restrictions have been, in some cases, a protection against predatory practices. The larger companies with larger administrative and legal expertise have been better able to cope with the problems and many wholesalers, jobbers, and retailers fear that their suppliers are thus able to expand downstream and put them out of business. Large refiners seem to be the main worry, although there is some concern about the small refiners who benefit from certain special treatment.

CONCERN ABOUT COMPETITION FROM REFINERS

Concern has been voiced that suppliers would effectively bankrupt their customers by one of four methods:

1. *Refusal to provide products.* A sizable number of retailers (and wholesalers) are apprehensive that they will lose their supplies with decontrol. Some have been told by their suppliers that they (the suppliers) intend to withdraw from particular market areas. Spokesmen for dealers who consider this a threat seem to believe that an abrupt pull-out must be avoided and that a 2 ½-year phaseout is appropriate.

Other retailers have been told by their suppliers that they (the suppliers) intend

to terminate their relationships with the particular retailers at the earliest practicable date. Such retailers generally favor special rule No. 4, usually with modifications, and/or a State set-asided program. Still others who are apprehensive of losing their supplies notably nonbranded independent marketers, favor the crude oil equalization tax and access to gasoline imports.

There is also the fear that certain established categories of customer will be abandoned. Marketers falling in these categories also want time protection and they want the option to transfer to other categories that will continue to be supplied.

Another concern is that suppliers will abandon deliveries to small full-service stations and concentrate on fewer high volume large stations on Main-traveled roads. These stations frequently require investment beyond the financial resources of the lessee dealers and owners of small stations. Time is required for these dealers to adjust.

The concern over abandonment of supplies is felt most directly by lessee dealers—operators of service stations who lease their stations from their suppliers, and who sell products under his trade name. Since they have no equity in the land or station they cannot go to a new supplier, and they have no vested rights that give them priority consideration at any new locations. It has been proposed that if service is to be discontinued, these dealers be given options to buy the station they now operate.

Those expressing concerns over abandonment of supply usually conceded the suppliers should have the right to maximize profits. They only want a guarantee that they will not be thrown out of business without reasonable chance to relocate, or to arrange new supplies.

2. *Direct marketing by refiners in low-cost, high-volume stations.* Throughout the testimony there appears a concern that the refiners are planning to increase their direct marketing operations by opening new efficient service stations. These company owned and operated stations would get best locations and best treatment. Marketers fear refiners are using their profits to finance expansion into gasoline stations rather than to expand refinery operation. Some have suggested that shares of output be frozen to the present proportion by class of customer and others (fewer) have suggested that refiners should be legally excluded from direct marketing. Dealers feel some protection is needed lest they be driven out of business by stations owned and operated by refiners. They point out that if they are out of business the refinery owned stations will be able to charge monopoly or oligopoly profits.

3. *Charging prices that make it impossible to make a profit.* Some dealers maintain that refiner-suppliers are increasing their participation in direct marketing operations and that they subsidize the operations of their new gasoline stations. Pump prices at these stations are alleged to be below the price which the independent station is charged. In order to avoid being forced out of business by what they consider discriminatory price practices, some wholesalers and retailers ask that prices of gasoline be exempted from controls but that the price differentials between classes of customers be maintained. Along this line, Continental Oil Co. has suggested that "component pricing could be implemented, which allows a marketer an opportunity to select a supplier because of the service and prices he offers."

4. *Adding hidden charges to the cost of gasoline.* Dealers complain that they will be charged for maps, a traditional courtesy at service stations, and that they will be charged for use of credit cards. Refiners have not denied that these steps are under consideration. In a free market this might be a cost item that would be offered by some suppliers and not by others depending on the benefits to the ultimate customer, but dealers fear that these steps during a transition period will put them at a disadvantage with company operated and discount competitors. To a lesser degree, customary business practice regulations are requested by many branded dealers (both lessee and operator owned) who are apprehensive that changes in credit terms and credit card practices will result in an additional squeeze upon their margins.

OTHER CONCERNS

Some refiners expressed a fear that exemption will be subject to conditions that will cause confusion and extra paperwork and that there will be restrictions that

impair the ability of the free market to react and give the most efficient determination of supplies and prices. Some trade associations and individual wholesale and retail marketers also express a fear that conditions attached to the exemption will work against them and believe it would be better to go to a completely free market.

Most State offices and many marketers expressed a belief that State offices would be more perceptive of the needs of the market and therefore they should be a key element in any transition scheme. Emergency supplies to meet problems that arise could better be handled at a local level. State set-asides are considered by some to be duplicative of the protection given by S.R. 4, but some feel that it should be provided in addition.

PRICE MONITORING AND EMERGENCY PLANS

The refiners generally advocate that no monitoring of prices be undertaken, and most specifically that there be no established trigger to reimpose controls. They maintain that this would have the effect of continuing controls in a veiled manner. Emergency plans are recommended by more of the marketers; some want the present system as a standby, but most seem to imply that a new pricing and allocation system with a new base is needed. Although most members of the industry oppose monitoring of their own operations, it is generally recognized that some record of prices and price changes is needed. Most commentors advocate avoidance of excess paperwork.

Price monitoring is generally not considered to be a good means to determine when controls may again be needed because processing of reports takes too long. Wholesaler, retailer, or State agency complaints about problems were suggested as offering a better indication of problems, and a more timely indication that action was called for. While many of the marketers recognized a need for standby controls none seemed to advocate a fixed set of recontrol indicators. Some commentors suggest that the exemption cannot be considered without the monitoring plan.

LEGISLATION

A number of retailers and some wholesalers indicated opposition to exemption until certain guarantees were incorporated into the law. One of the most frequently expressed "needs" was passage of HR 130, which would give dealers some protection against a complete cut-off of supply. Many consider this is the most important single feature.

The crude oil equalization tax was also considered important by some. It is also considered important that imports be available to the wholesaler so that they have an alternative to domestic refined products in a rising market.

PRICE DIFFERENCE BETWEEN LEADED AND UNLEADED GASOLINE

In addition to questions surrounding the supply of unleaded gasoline, a number of comments were directed at the existing and potential price differential between leaded and unleaded gas. The Administrator of the Environmental Protection Agency commented to FEA in connection with its August 9 proposal, agreeing with the central finding of the report that current conditions do not warrant the continuation of price and allocation controls and that no shortage of gasoline is likely to occur in 1979. However, he indicated concern over the spread between the prices of regular and unleaded grades of gasoline and asked for an analysis of the potential impact of decontrol on the relative prices of unleaded and leaded grades. He further urged that provision be made for the reimposition of price controls should the spread between these two grades increase significantly.

In a statement made by EPA at the public hearing on November 30, the concerns were discussed more specifically. In general, automobiles since 1975 have used catalytic converters to meet air pollution control standards. Because lead, which is added to gasoline to boost the octane rating, destroys the effectiveness of these converters, EPA required the use of unleaded gas in vehicles using them. In addition, EPA requires cars requiring unleaded gas be equipped with a filler inlet restricter. Only the smaller nozzles which are required on pumps dispensing unleaded gas fit these cars.

It is illegal for a retailer or a fleet owner to introduce leaded gasoline into a car requiring unleaded. Because of this and the practical difficulty of "switching" if the small nozzles are on unleaded gas dispensers, and the small price differential between leaded and unleaded gaso-

line is not thought to provide sufficient incentive for the customer to purchase leaded gasoline for use in cars requiring unleaded. However, as the price differential increases, it is feared that the incentive to save the difference in price is likely to lead to more widespread "switching."

EPA admittedly does not have reliable information about the rate at which "switching" may be occurring although it has violations, especially among fleet owners. A recent survey revealed that about 10 percent of those automobiles required to use unleaded actually refueled with leaded. EPA has little confidence in the 10 percent figure and admits it could be higher or lower.

EPA indicates it is attempting to enforce its unleaded gasoline regulations by initiating an effort to prohibit removal of the filler inlet restricters and by an educational campaign by major gasoline marketers to notify their customers of the retailers legal liability. However, they state that no reasonably sized enforcement program can be completely effective at 300,000 gas stations if there is a substantial incentive for noncompliance. They ask that in the event of removal of existing controls, institution of controls on retail price differentials between leaded and unleaded should be considered.

In a few other presentations similar concerns were expressed. And some said the problem was sufficiently serious that an environmental impact statement should be prepared. The Office of General Counsel believes that the procedural question concerning the EIS is one that must be resolved by the Secretary.

A large number of arguments against a mandated price differential were presented, particularly by larger refiners. The basic arguments are: (1) EPA's request to the Commission (or the Department) to implement price controls in this area is an abrogation of its own responsibility to enforce its own regulations; (2) The problem of catalyst abuse, particularly in the early stages was predictable; the existence and scope of self-service gasoline stations was known, the price differences between gasoline grades and brands is not new; (3) intense competition for customers will work in this area as well as it is now working in the leaded area; (4) EPA should in addition to enforcing existing law, seek new authority, if needed, to cause automobile manufacturers to make it impossible to use leaded gasoline in converter equipped cars; (5) it is not legal to retain or institute controls only on price differentials; (6) the problem is one that should be solved by periodic mandatory inspection of motor vehicles and consumer education.

There is general agreement that leaded regular is the price leader in many markets now. As the use of unleaded gasoline increases, as it will by about 9 percent per year, competition should occur in both leaded and unleaded. Thus, wholesalers or retailers who attempt to unjustifiably raise the differential for unleaded gasoline will be curtailed by competition. Some commenters noted that even now, although there are some high differentials, many retailers continue to offer unleaded gasoline at differentials of 2 to 3 cents per gallon. In summary, the argument against controls in this area is that the gasoline consumer has demonstrated mobility in seeking the best bargain and will continue to do so. Price has always been a major factor in the consumers' decision on where to trade, and those who wish to find unleaded gas will seek out the lowest price. Accordingly, the most effective regulator in this area will be competition.

It was also noted by many that the problem of the differential began in a period of price control and continues under controls. If the price of unleaded is restrained there may be no incentive to increase capacity to refine it. In addition to raising some of the arguments set forth above, the Council on Wage and Price Stability believes that EPA proposal could, if implemented, cause substantial cost increases in leaded gasoline. It considers this to be a regulatory proposal requiring an economic analysis of the costs to be incurred.

Conclusions and Recommendations

After reviewing the proposals and the record of this proceeding and consulting with the Secretary of Energy, the Commission has reached the conclusions set forth below.

The Commission concurs in the proposals of the Secretary that would exempt motor gasoline from the mandatory pricing and allocation regulations. It

should be noted that no alternative system of price or allocation controls was proposed or discussed in this proceeding. Therefore the question before the Commission was limited to whether or not the existing system of controls should be continued.

The existing system of controls was divised to cope with an emergency and is not necessary nor effective in a period of adequate supply. Moreover the Economic Regulatory Administration agrees that the present system of allocation controls would not be effective in the event of a supply interruption, and should be restructured for use as a stand-by system.

During this proceeding there was virtually unanimous agreement that the present system of allocation controls is overly complicated, difficult to understand, expensive to comply with, and extremely burdensome, particularly to the smaller businessman.

With respect to price controls, data indicates that in the present market, gasoline is generally being sold below ceiling prices. The need for price controls is of course, heavily dependent on the forecast of supply and demand. The projections by DOE indicate that no serious shortage of gasoline is expected, with or without exemption from controls. Prices will probably increase in either case due to higher costs of crude oil and necessary increases in non-product costs. Assuming an adequate supply of gasoline, the extent to which the increased costs will be passed on to the consumer will be dictated, as it is now, by market conditions.

Information in the record indicates that exemption from controls may encourage refiners to increase their capacity. It seems relatively clear that the lack of investment in added capacity over the past years is at least partly due to the inhibiting nature of price controls. Accordingly the Commission agrees with the Secretary's conclusion that to the extent supply is limited by lack of refining facilities, exemption from controls can only be a favorable factor, although there is no guarantee that exemption will in fact spur new investment.

The DOE projection of the demand for gasoline is necessarily dependent on developments which cannot be predicted with certainty. Although some questions regarding the analysis were raised and some alternate statistics presented, there was no competing comprehensive supply-demand analysis presented. The Secretary's analysis is a reasonable one and seems to bear up under examination. Accordingly the Commission concurs with the Secretary in relying on the analysis and believes that the required statutory findings which are related to it, are reasonably made.

The widespread dissatisfaction with the allocation system does not mean there is agreement that the system should be terminated immediately. A transitional program is favored by most marketers downstream of the refiners and appears to be necessary to insure that there will be a reasonable period in which to readjust supplier-purchaser relationships. There were a number of alternatives to the Secretary's one year transition program, i.e., Special Rule No. 4. Some groups favored a longer period, some more elaborate and possibly unadministerable systems, such as guaranteeing marketers a profit. Some suggested, and the Commission agrees, that Special Rule No. 4, should be modified to increase the protection given to marketers by deleting the requirement that the purchasers must take supplies in any three month period or lose their entitlements. The deletion of this provision, paragraph (f) of the Rule, should insure that those marketers who make good faith efforts to obtain new long term contracts, will have access to supplies for the full transitional year. Accordingly, the Commission concurs in the adoption of Special Rule No. 4 with the recommendation pursuant to § 404(b)(2) of the DOE Act, that paragraph (f) of the Rule be deleted.

In the course of its consideration of this matter the Commission noted several areas of concern. Although no recommendations for changes under § 404(b)(2) were made with respect to these concerns, they were brought to the Secretary's attention.

The following correspondence sets forth the Commission's preliminary findings and concerns, the Secretary's response thereto, and the final recommendations of the Commission.

By the Commission.

KENNETH F. PLUMB,
Secretary.

¶ 31,988

APPENDIX A

FEDERAL ENERGY REGULATORY COMMISSION, WASHINGTON, D.C.

Hon. JAMES R. SCHLESINGER, *Secretary*, Department of Energy, Washington, D.C.

FEBRUARY 3, 1978.

DEAR MR. SECRETARY: By letter of October 19, 1977, you forwarded to the Federal Energy Regulatory Commission (Commissior) proposed amendments to the regulations under the Emergency Petroleum Allocation Act (EPAA) that would exempt motor gasoline from both the Mandatory Petroleum Allocation Regulations and the Mandatory Petroleum Price Regulations. You also forwarded proposed "Special Rule No. 4," which would establish a transitional motor gasoline assignment program to be in effect for one year following the exemptions, if the exemptions become effective. The Commission is considering the exemption amendments pursuant to section 402(c)(1) of the Department of Energy Organization Act (DOE Act) and Special Rule No. 4. under Section 404(a) of the DOE Act.

Based on our review of this matter, the Commission has arrived at the following preliminary conclusions: the methodology used to evaluate this issue and on which the proposed amendments are based is reasonable, and the findings are appropriate. Accordingly, the Commission, by this letter, advises you that we have made the tentative determination to concur in the proposals to exempt motor gasoline from the pricing and allocation regulations without making any "recommendations" as contemplated in sections 404 (b) and (c) of the DOE Act. With respect to Special Rule No. 4, the Commission concludes that the protection for marketers, to be derived from the one year continuation of the supplier-purchaser relationship, is necessary. The Commission does, however, make a formal recommendation that Paragraph (f) of Special Rule No. 4 be deleted. The Commission believes that purchasers need the assurance of continued access to a source of supply for one year. The three month "use it or lose it" feature of Paragraph (f) appears to be unnecessarily restrictive, mantle of protection deficient. Therefore, the Commission recommends that you substitute for Paragraph (f) a requirement that the purchaser, upon receipt of notification from its supplier that the supplier-purchaser relationship will be terminated, notify said supplier whether it wishes to maintain its right to receive its allocation during the one year period following exemption. Such a requirement would permit the supplier to better utilize its available supply yet provide the purchaser maximum flexibility for utilizing the one year assurance of continued access to a source of supply. The Commission intends to make this recommendation within the contemplation of Sections 404(b) and 404(c) of the DOE Act.

The Commission herein solicits your responses on these preliminary determinations. Your comments will fulfill our obligation to consult with the Secretary prior to issuance of our final recommendations as required under Section 404(b) of the DOE Act.

In addition, the Commission wishes to call your attention to three areas of concern, with regard to which we look forward to receiving your views.

In the proceedings before the Commission a number of participants stated that enactment of H.R. 130 (Dealer Day in Court legislation) was a necessary prerequisite to exemption. This legislation, which provides additional protection to franchised dealers, is of particular importance to major branded dealers. While the Commission makes no recommendation relating to this pending legislation, we wish to bring to your attention the concern expressed in this regard by several of those who participated in our proceedings, especially since one of the policy objectives in Section 4(b)(1) of the Emergency Petroleum Allocation Act is to "* * * preserve the competitive viability of * * * branded independent marketers."

A second area of concern relates to establishing a monitoring program to review the price of motor gasoline subsequent to the exemption. A number of participants had views on this subject, ranging from assertions that the proposed exemption could not be evaluated apart from the monitoring system to allegations that no monitoring system is necessary. It is our understanding that the Secretary is presently developing a comprehensive program to monitor gasoline supply and prices at each of the levels in the distribu-

tion chain. The Commission recognizes that such a system might constitute a burden, particularly on the small businessman, but we conclude that the monitoring system would be useful to measure the impact of decontrol, and to provide a basis for a timely response should the market respond differently than predicted. Accordingly, the Commission wishes to note its support for your effort to develop and implement a reliable gasoline supply and price monitoring program at each level of the industry.

Finally, some participants expressed concern over a possible increase in the price differential between leaded and unleaded gasoline. Although it appears likely that competition for the unleaded user's business will keep the price of unleaded gas from rising disproportionately, the Commission believes that this price differential should be closely monitored. We would also suggest that steps be taken in cooperation with the Environmental Protection Agency to develop contingency responses to deal with any unjustified increase in this price differential.

As stated above, the preliminary determinations and views of the Commission included in this letter are forwarded to you for consideration. As required by Section 404(b), the Commission will await your response before taking final action with regard to the proposed exemption and Special Rule No. 4.

By direction of the Commission.

CHARLES B. CURTIS,

Chairman.

APPENDIX B

DEPARTMENT OF ENERGY,

Washington, D.C., March 7, 1978.

Hon. CHARLES B. CURTIS,

Chairman, Federal Energy Regulatory Commission, Washington, D.C.

DEAR MR. CHAIRMAN: This is in response to your letter of February 13, 1978, concerning the tentative determination of the Commission to concur in the proposals to exempt motor gasoline from the Mandatory Petroleum Allocation and Price Regulations. As part of the consultation process contemplated by Section 404 of the Department of Energy Organization Act, Pub. L. 95-91 ("DOE Act"), you solicited my response to the Commission's preliminary determinations, as well as to other concerns the Commission has in this matter, before issuing the final recommendations permitted by Section 404.

With respect to Special Rule No. 4, the proposed transitional assignment program for the post-exemption period, you advise that the Commission has tentatively agreed that such a program is necessary for a one year period. However, the Commission intends to recommend formally the deletion of paragraph (f) of the proposal, which would have required wholesale purchasers to continue purchasing their full allocation entitlement from their base period supplier in order to remain eligible for relief under the Special Rule. Instead, the Commission recommends that a provision be substituted whereby a purchaser receiving a notice from its base period supplier terminating a supplier/purchaser relationship would be required to notify its base period supplier that it wishes to maintain its right to receive its allocation during the one year period following exemption.

I accept the tentative recommendation that paragraph (f) of the proposed Special Rule be deleted in order to amplify the protection to be afforded marketers. However, rather than inserting the substitute notification provision the Commission suggests, I suggest as an alternative that paragraph (b) of the proposed Special Rule be changed by deleting the requirement that purchasers apply for continuation of their existing supplier/purchaser relationship at least 30 days before a termination would be effective. This change would permit continuation or reestablishment of the relationship at any time during the year following the effectiness of the exemption. This would provide even greater assurance that purchasers would have "continued access to a source of supply for one year" than the Commission's own proposal, would give the supplier greater flexibility in utilizing its available supply, and would provide a more gradual transition into a decontrolled market. I therefore respectfully request that the Commission consider this alternative as its final recommendation. The proposed language of this alternative is enclosed.

You also noted three other matters, not the subject of Commission recommenda-

tions, raised by public comments received by the Commission. First, you note the importance of the enactment of pending Federal legislation relating to dealer franchise protection (H.R. 130, the "Dealer Day in Court" bill) to major branded dealers. The Department strongly supports franchise protection legislation for motor gasoline dealers that would protect them from arbitrary loss of franchises. You also noted Commission support for a reliable gasoline supply and price monitoring program at each level of the industry and a concern over possible increases in price differentials between leaded and unleaded gasoline following decontrol. We expect to develop and implement an appropriate price monitoring system that would, among other things, monitor the leaded-unleaded price differential. As you suggest, we intend to consult with the Environmental Protection Agency in the development of any contingency measures that may be necessary to prevent or correct any unjustified increases in the differential. We are reviewing specific monitoring alternative, and intend to avoid undue burdens, particularly upon small businesses.

Sincerely,

JOHN F. O'LEARY,

Deputy Secretary.

Enclosure (see Appendix C for identical enclosure).

APPENDIX C

FEDERAL ENERGY REGULATORY COMMISSION,

Washington, D.C., March 29, 1978.

Hon. JAMES R. SCHLESINGER,

Secretary, U.S. Department of Energy, Washington, D.C.

DEAR MR. SECRETARY: By letter of October 19, 1977, you forwarded to the Federal Energy Regulatory Commission (Commission) certain proposed amendments to the regulations under the Emergency Petroleum Allocation Act (EPAA) that would exempt motor gasoline from both the Mandatory Petroleum Allocation Regulations and the Mandatory Petroleum Price Regulations. You also forwarded proposed "Special Rule No. 4" which would establish a transitional motor gasoline assignment program to be in effect for one year following the exemptions, should the exemptions become effective. These actions were predicated upon your findings that,

(a) The exemptions are consistent with the public policy objectives in Section 4(b)(1) of the Emergency Petroleum Allocation Act;

(b) Motor gasoline is no longer in short supply and that the exemption will not have an adverse effect on the supply of oil or other products; and

(c) Competition and market forces will provide adequate protection for the consumer and the exemption will not result in inequitable prices for any class of user.

The Commission has considered the proposed exemptions pursuant to Section 402(c)(1) of the Department of Energy Organization Act (DOE Act) and Special Rule No. 4 under Section 404(a) of the DOE Act.

Since this is the first such review under the DOE Act, the Commission prefers first to outline its understanding of its legal responsibility under that statute. Since the statute also incorporates portions of the Emergency Petroleum Allocation Act and the Energy Policy and Conservation Act, we have undertaken a detailed review of the legislative history of the EPAA, the pertinent amendments to the Act, and the history of the Energy Policy and Conservation Act.

The DOE Act intended to vest in a collegial body, independent of the Secretary, major energy pricing and licensing matters, including "energy actions." The law also provided, however, that the Secretary retain the authority to propose energy actions, the final authority to submit such actions to Congress and the responsibility for implementation of the pricing and allocation programs. The Commission has concluded that the insertion of the Commission in the process leading up to the submission of a proposed exemption to the Congress did not change the basic nature of the exemption process. The DOE Act continues to place reliance on the expertise of the Secretary and his employees and contemplates the Commission according due weight to the judgment of the Secretary in these matters.

In performing its responsibilities with respect to the proposals at hand, the Commission has reviewed the record of the proceedings before the Federal Energy Administration as well as the record before the FERC. The Commission recognizes that the law does not require that a record be developed to support those findings which the President must make prior to forwarding a proposed exemption to Congress. More specifically, although procedures applicable to informal rulemaking were observed, there is no requirement that the findings be based on that proceeding, nor on any other record developed expressly for the purpose of proposing the exemptions. Nevertheless you have provided us with a detailed analysis of the information supporting your conclusions with regard to the exemptions. This, together with the written and oral comments generated by these proposals, forms a substantial record on which the Commission has relied extensively.

We wish to emphasize that the question presented to the Commission and the one discussed by the participants in this proceeding was whether motor gasoline should be exempted from the existing price and allocation regulations. Whether or not alternative regulatory measures would be feasible and/or desirable was not an issue raised or addressed in the record and accordingly has not been considered by the Commission.

Within this context, the Commission considered the asserted findings and the accompanying analysis. The Commission also reviewed your analysis of the potential impact of the proposed exemptions.

By letter of February 3, 1978, the Commission informed you of its preliminary conclusions regarding the proposed exemptions and Special Rule No. 4. The letter advised you that the Commission had tentatively decided to concur in the proposals to exempt motor gasoline from the mandatory pricing and allocations regulations without making any recommendations pursuant to § 404 (b) and (c) of the DOE Act.

With respect to Special Rule No. 4, the Commission notified you that it intended to make a formal recommendation that the three-month "use it or lose it" feature of paragraph (f) of the Rule be deleted. The Commission suggested that paragraph (f) be replaced by a notification requirement. The letter indicated that the Commission believed the deletion of paragraph (f) "* * * would permit the supplier to better utilize its available supply, yet provide the purchaser minimum flexibility for utilizing the one-year assurance of continued access to a source of supply."

In addition to the recommendation with respect to Special Rule No. 4, the Commission noted three other areas of concern, viz. the relevance to this matter of H.R. 130 (Dealer Day in Court legislation) the need for a comprehensive monitoring system, and the potential price differential between leaded and unleaded gasoline.

Your response to the preliminary determinations was solicited with the understanding that the correspondence would fulfill our obligation to consult with the Secretary prior to issuance of our final recommendations.

Deputy Secretary John O'Leary's letter of March 7, 1978, has been received and reviewed by the Commission. The letter indicated acceptance of the tentative recommendation that paragraph (f) of Special Rule No. 4 be deleted, but suggests an alternative to the reporting requirement suggested by the Commission. Specifically, it is proposed to delete that requirement in paragraph (b) of the Rule that "* * * purchasers apply to a regional office for an assignment at least 30 days before a termination would be effective." With the necessary conforming changes, the suggestion would result in marketers having the right to continue or reestablish their purchaser/supplier relationship for a period of one year, if their good faith efforts to secure a different supplier failed.

The Commission concludes that the alternative suggested is a reasonable one, and is supported by the record and reasons stated in the letter. It is consistent with the Commission's intent to permit suppliers to utilize available supplies and, most important, provides purchasers maximum assurance of a continued access to some source of supply for a full year.

The Commission also notes the response to three areas of concern cited in its February 3, 1978 letter. It supports the De-

partment's efforts to develop a comprehensive monitoring system which will include the price differential between leaded and unleaded gasoline. The Commission has reviewed the record regarding this price differential and concludes that the arguments against using the mandatory pricing regulations to control the differential are persuasive. Accordingly, the Commission makes no recommendations pursuant to §404 with respect to the pricing of leaded/unleaded gasoline.

The examination that we made does not provide a basis for reaching a conclusion different from your finding that competition and market forces will provide adequate protection for the consumer and the exemption will not result in inequitable prices for any class of user. However, the Commission does invite your attention to the fact that some commentors expressed fear that under exemption the supplier may pull out of low density markets with some serious loss of service to rural populations. Related to this was a set of letters to FERC, and before that to FEA, which represented that higher gasoline prices would diminish various social services and increase the isolation of residents in remote rural areas. By logical extension such concerns are also related to the transportation isolation of residents in high density, low income urban areas.

It is not clear precisely what significance gasoline prices do, or the present system of allocation and price regulation does, in fact have to these matters. If any significant relationship should be found, it would influence mobility, employment opportunity and community stability. It is not clear, moreover, to what extent regulatory control with respect to gasoline would be an efficacious method of public action.

Although these matters were not well formulated or supported in the record upon which we have made this review, they merit further attention. The Commission therefore suggests that, as a part of the implementation of the decontrol proposal, the Department of Energy should undertake intensive analysis of the parameters of these problems with a view toward developing such adjustment measures as may be indicated.

In summary, the Commission after consultation with the Secretary concurs in the adoption of the proposals to exempt motor gasoline from the provisions of the mandatory pricing and allocation regulations. We concur in the adoption of Special Rule No. 4 with the recommendation that paragraph (f) of the Rule be deleted. The Commission also recommends that paragraph (b) of the Rule be changed to delete the requirement that purchasers apply for continuation of their existing supplier/purchaser relationship at least 30 days before a termination would be effective. The Commission further recommends that certain conforming changes in the Rule be made. The revised Rule, incorporating the Commission's recommendations is attached.

By direction of the Commission.

KENNETH F. PLUMB,
Secretary.

PROPOSED REVISIONS TO SPECIAL RULE NO. 4, APPENDIX TO SUBPART A, PART 211, TITLE 10 OF THE CODE OF FEDERAL REGULATIONS

(Additions to proposed special rule appearing at 40920 FEDERAL REGISTER, August 12, 1977, indicated by *italics;* deletions indicated by brackets.)

1. *Scope.* Notwithstanding the exemption of motor gasoline from the Mandatory Petroleum Allocation Regulations, this Special Rule provides for the establishment of a transitional assignment program for motor gasoline for the months [__1977 through__1978].

2. *Transitional assignment program.* Notwithstanding any contrary provisions of parts 205 and 211 of this chapter, assignments of base period supplies and base period use for wholesale purchasers of motor gasoline shall be made in accordance with the provisions of this Special Rule.

(a) No supplier/wholesale purchaser relationship in effect under §211.9 of this part as of [__1977,] may be terminated before [__1978] by a supplier except upon written notice to the wholesale purchaser given at least ninety (90) days prior to the date on which the supplier intends to terminate the supply relationship. A termination under this paragraph (a) may only be effective at the end of the period corresponding to a base period coinciding with or following the expiration of the ninety (90) day notice period. Any such ninety (90) day period may not begin prior to [__1977].

(b) Any wholesale purchaser which has received a notice from its supplier under paragraph (a) above shall make a diligent effort to locate an alternate source of supply. If its effort is unsuccessful it may apply to the appropriate DOE Regional Office for a continuation *or reestablishment* of its [current] *most recent mandatory* supplier/purchaser relationship, [but any such application shall be made at least thirty (30) days prior to the date on which the termination under paragraph (a) is to become effective.] The applicant shall certify to the DOE that it has made a diligent unsuccessful effort to locate an alternate source of supply and shall set forth in its application (i) the name and address of its base period supplier; (ii) its base period use with that supplier for each period corresponding to a base period; and (iii) the names and addresses of other suppliers contacted with respect to the applicant's efforts to locate an alternate source of supply, the volumes requested from each such other supplier, and the dates of those contacts. The applicant shall send a copy of its application to its base period supplier.

(c) If DOE determines that an applicant has made a diligent unsuccessful effort to locate an alternate source of supply, DOE shall order a continuation *or reestablishment* of the applicant's [existing] *most recent mandatory* supplier/purchaser relationship for a period of *up to* three consecutive periods corresponding to a base period. While a continuation *or reestablishment* order is in effect, the wholesale purchaser shall again make a diligent effort to locate an alternate source of supply. If the wholesale purchaser is again unsuccessful, it may again apply for a continuation *or reestablishment* in accordance with paragraph (b) above.

(d) If DOE fails to take action on a timely filed application under paragraph (b) of (c) *filed at least 30 days* prior to the date upon which the termination of the supplier/purchaser relationship which is the subject of the application is to become effective, the supplier/purchaser relationship shall be automatically extended for a period of one (1) month pending DOE action on the application. If DOE fails to take action on a late filed application under paragraph (b) or (c) *filed less than 30 days* prior to the date upon which the [termination of the supplier/purchaser relationship] *relief* which is the subject of the application is to become effective, DOE may [issue] *order* a temporary continuation [order] *or reestablishment of a supplier/purchaser relationship* for a period of one (1) month pending DOE action on the application upon a showing by the applicant of good cause for the late filing.

(e) [DOE may issue with respect to any supplier/purchaser relationship no more than three (3) continuation orders.] In no event may the provisions of a continuation order be effective beyond —1978.

[Paragraph (f) deleted in its entirety]

3. *Non-discrimination requirement.* To prohibit any form of discrimination (including price discrimination) which has the effect of circumventing, frustrating, or impairing the objectives, purposes and intent of this Special Rule, the requirements of paragraph (b) of § 210.62 of this chapter shall continue to apply to suppliers which are subject to a continuation order under the traditional assignment program of this Special Rule, and to all suppliers which are still supplying purchasers because they have failed to give notice of intent to terminate supplies or such termination has not yet become effective.

—Footnotes—

[1] Since the projections were for the total market for gasoline, the absence of estimates from three respondents does not affect the accuracy of any of the projections.

[2] i.e., equipment to process the output from units that refine crude oil.

[3] Unleaded gasoline components require more input at processing units to produce a given quantity at a given octane rating than if lead is used to upgrade octane quality.

[4] John H. Shenfield and Joe Sims, "Comments of the Department of Justice" (in FERC Docket No. EA78-1) U.S. Department of Justice, Washington, D.C., December 5, 1977, p. 14-15.

¶ 31,989 Short-Form License and Associated Standardized Conditions (L-Form)

43 F.R. 18196 (April 28, 1978).

[18 CFR Parts 2, 3, 4, 131]

[Docket No. RM78-9]

SHORT-FORM LICENSE AND ASSOCIATED STANDARDIZED CONDITIONS (L-FORM)

APRIL 21, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: The Commission gives notice that it proposes to amend its rules and regulations in order to establish a short-form hydroelectric license with related standard conditions (L-Forms). In addition, a new application form would be established with accompanying instructions for completing the application for a short form license. The purpose of the proposed rulemaking is to provide a simplified procedure and format for processing applications for small-scale hydroelectric projects that meet specific size criteria. Availability of such procedures would save time for the applicant and the Commission staff. It would encourage the development of small capacity hydroelectric projects in furtherance of national policies for conservation of fossil fuels.

DATES: Comments should be submitted not later than May 23, 1978.

ADDRESSES: Secretary, Federal Energy Regulatory Commission, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Ronald Corso, Office of Electric Power Regulation, 202-275-4863; Raymond Hagenlock, Office of the General Counsel, 202-275-4271.

SUPPLEMENTARY INFORMATION: Pursuant to section 553, Title 5, United States Code, and sections 4(e), 9, 10, and 309 of the Federal Power Act (Act) (41 Stat. 1065-1066, 1068-1069, 49 Stat. 840-841, 858-859, 61 Stat. 501; 16 U.S.C. 797(e), 802, 803, and 825h), and sections 402 and 403 of the Department of Energy Organization Act (Pub. L. 95-91, 91 Stat. 565), the Commission gives notice that it proposes to amend specific sections of the rules and regulations in order to establish a short-form hydroelectric license with related standard conditions (L-Forms). In addition, a new application form would be established with accompanying instruction for completing the application for a short-form license.

The purpose of this proposed rulemaking is to provide a simplified procedure and format for processing applications for small-scale hydroelectric projects that meet specific size criteria as stated herein. Availability of such procedures would save time for the applicant and the Commission staff. It would encourage the development of small capacity hydroelectric projects in furtherance of national policies for conservation of fossil fuels. For example, considerable impetus and increased attention is being given to hydroelectric projects as a result of the Administration's energy policies (such as the incentive program for projects less than 15 megawatts included in the National Energy Act proposals now under consideration by a Joint Conference Committee of the U.S. Senate and House of Representatives).

There has been a sharp increase in the number of inquiries and applications received by Commission staff in recent months concerning the installation of additional generating capacity at existing hydroelectric projects, the redevelopment of existing projects to provide additional power, and the installation of power generating facilities at existing nonpower dams. Indications are that this interest will result in sharply increased numbers of applications being filed with the Commission in the future.

Constraints imposed by the Federal Power Act inhibit to some extent the ability of the Commission to expedite action on applications. However, with regard to projects of 2,000 horsepower or less, the Commission has availed itself in the past of the authority provided in section 10(i) of the Act, 16 U.S.C. 803(i), to "waive such conditions, provisions, and requirements" of part I of the act as may be deemed in the public interest to waive under the circumstances. The only exclusions to this waiver authority in section 10(i) are the granting of license periods longer than 50 years and changes in the requirements for annual charges for use of lands within Indian reservations.

In an effort to reduce the burden of application preparation for small projects, the Commission's regulations currently require considerably less detail in applications for projects of 2,000 horsepower or less (approximately 1,500 kilowatts) than for larger projects. Section 4.60 of the regulations requires use of the format prescribed by section 131.6 of the regulations for such projects.

However, utilization of the provisions of § 131.6 does not always result in the expected savings of time and effort in the processing of applications. This is generally due to the quality of the application initially received (i.e., the extent to which the application conforms to the requirements of the regulations). Experience shows that applicants are often unable to obtain (or understand) the regulations. Staff analysis shows that potential time savings are also often unrealized for other reasons such as delays in receipt of comments from affected Federal, State, and local agencies with respect to the application, low priority of small projects versus those producing substantial blocks of new generating capacity, occasional protests or interventions, etc. The overall result is that a minor project application with no complex features routinely requires from 6 to 9 months to be processed for Commission consideration for licensing. The Commission by this rulemaking seeks to simplify the licensing process for small hydroelectric projects.

To reduce the time required to process applications for licenses for small projects, a "short-form" application and license is proposed. In brief, the intention is to develop a simple application format which could be completed by an applicant following instructions furnished with the form, attaching only the minimum drawings, certifications, etc., necessary to meet the requirements of the Federal Power Act and other applicable statutes. Compared to the present regulations, the proposed short-form application would lessen the descriptive information needed, reduce the details required on maps and drawings, and simplify the requirements for complying with the National Environmental Policy Act (NEPA), 42 U.S.C. 4321 et seq., without compromising environmental considerations.

To provide for the broadest applicability of the proposed procedure to the Commission's workload, and to ensure compliance with applicable statutes, it would be necessary to impose certain limitations on utilization of the proposed procedure. The "Short-form" procedures would not be used on any projects:

(1) Having a dam or diversion structure more than twenty-five (25) feet in height above stream bed,

(2) Impounding a reservoir having a surface area of 10 acres or more,

(3) Exceeding 2,000 horsepower (1,500 kilowatts).

The first criterion was chosen because it is consistent with the National Dam Inspection Act, 33 U.S.C. 467a-467e, that is, dams of this size would likely be in a low hazard category. The second criterion was chosen because it is consistent with the Fish and Wildlife Coordination Act, 16 U.S.C. 661-666c, that is, formal consultation with the Federal and State fish and wildlife agencies is not required when the maximum surface area of the impoundment is less than 10 acres. And the third criterion was chosen based upon section 10(i) of the Federal Power Act as explained above.

There would be no limitation on the status of the applicant, i.e., it may be an individual, an association, a State, a municipality, a corporation, or other entity. Appropriate identification of the applicant's status would be required.

If the project were proposed for development on Federal lands, the applicant would be required to apply for any appropriate permits required by the agency having jurisdiction over the Federal lands involved.

Applicants for proposed projects would be required to consult with appropriate Federal, State, and local resourcers agencies during the preparation of the applications and provide interested agencies with the opportunity to comment on the proposal prior to its filing with the Commission. The comments of such agencies would be attached to the application when filed.

When the application is found to be in conformance with the regulations and acceptable for processing, a public notice would be issued by the Commission pursuant to section 1.19(b) of the Commission's regulations and section 4(e) of the Act, 16 U.S.C. 797(e). This notice would

afford an opportunity for Federal, State, and local agencies, and the general public, to inform the Commission of objections to the proposed project, or to provide conditions which the agencies believe should be included in any license which may be issued. We emphasize that applications for such projects would not be forwarded to Federal, State, and local agencies for comments. Public notice issued by the Commission would be in sufficient detail to describe the project and its purpose so that agency input in response to public notice could be adequately provided. Copies of the public notice would be individually sent to appropriate agencies in addition to the normal publication in newspapers and in the FEDERAL REGISTER. The expanded public notice would include additional descriptive information and a map. Although the FEDERAL REGISTER notice would not include such a map, it would indicate that a map could be obtained from the Commission or the applicant upon request. Application guidelines also require contacts with appropriate agencies prior to filing of the application. The Commission believes these procedures comply with section 4(e) of the Federal Power Act and other statutes.

With respect to NEPA and the Commission's regulations related to NEPA, specifically section 2.80 et seq., the Commission's staff would continue to prepare environmental assessments of the proposal during the review and analysis of each application as is done at present. The information submitted by the applicant as provided for in the new application form, together with the comments and analysis received from interested agencies and members of the public, as well as the independent evaluation of the staff, will form the basis for the ultimate determination of whether an individual proposal will or will not be a major Federal action significantly affecting the quality of the human environment.

The license order would become final 30 days from the date of issuance unless an application for rehearing were filed in accordance with section 313(a) of the Act, 16 U.S.C. 8251(a). Failure to file such an application would constitute acceptance of the license. Acknowledgement of acceptance of the license would be required to be provided to the Commission within 60 days of the date of issuance of the order.

The proposed amendment to the Commission's rules and regulations under the Federal Power Act would be issued under the authority granted the Federal Energy Regulatory Commission by the Federal Power Act, as amended, particularly sections 4(e), 9, 10, and 309 (41 Stat. 1065-1066, 1068-1069, 49 Stat. 840-841, 858-859, 61 Stat. 501; 16 U.S.C. 797(e), 802, 803, and 825h), sections 402 and 403 of the Department of Energy Organization Act (Pub. L. 95-91, 91 Stat. 565) and E.O. 12009, 42 FR 46267.

PART 3—ORGANIZATION; OPERATION; INFORMATION AND REQUESTS

In order to implement the subject matter considered above, the Commission proposes to amend Part 3, Subchapter A—General Rules, Chapter I, Title 18, Code of Federal Regulations, by deleting the word "major" from § 3.114(b). As amended, § 3.114(b) will read:

§ 3.114 Licenses.

* * * * *

(b) Applications under the Federal Power Act for license authorizing construction of projects; for license for constructed projects; and for renewal of licenses for projects are processed in the manner stated in § 3.133.

* * * * *

PART 4—LICENSES, PERMITS, AND DETERMINATION OF PROJECT COSTS

2. The Commission proposes to amend Part 4, Subchapter B—Regulations Under the Federal Power Act, Chapter I, Title 18, Code of Federal Regulations, by adding a new § 4.61 to read as follows:

§ 4.61 Contents.

(a) Each application for a short-form license for a small-scale hydroelectric project, whether constructed or to be constructed, shall conform to § 131.7 of this chapter and shall be filed in accordance with § 4.31 of this chapter.

(b) Short-form licenses are restricted to constructed or unconstructed hydroelectric projects which have or will have generating capacity of 2,000 horsepower (1,500 kW) or less, do not include dams or diversion structures over 25 feet in height above stream bed, and do not impound a reservoir having a surface area of 10 acres or more.

PART 131—FORMS

3. The Commission proposes to amend Part 131, Subchapter D—Approved Forms, Federal Power Act, Chapter I, Title 18, Code of Federal Regulations, by adding a new § 131.7 to read as follows:

§ 131.7 Application for short-form license.

(See § 4.61 of this chapter.)

APPLICATION FOR
SHORT-FORM LICENSE

1. Applicant's full name and address: _____
(Zip Code)
2. Location of Project:
State:_____ County:_____
Nearest Town:_____ Stream:_____
3. Project description and proposed mode of operation (reference to Exhibit K and L, as appropriate):

(continue on separate sheet if necessary)
4. Lands of the United States affected (shown on Exhibit K)

	(Name)	(Acres)
a. National Forest	_____	_____
b. Indian Reservation	_____	_____
c. Public Lands under jurisdiction of	_____	_____
d. Other	_____	_____
e. Total U.S. Lands		_____

f. Check appropriate box:

☐ Surveyed ☐ Unsurveyed land in public-land state:

(1) If surveyed land in public-land state provide the following:
Sections and subdivisions:_____
Range_____ Township:_____
Principal base and meridian:_____

(2) If unsurveyed or not in public-land state, see Item 7 of instructions:_____

Purpose of project (use of power output, etc.)
6. Construction of the project is planned to start_____ It will be completed within_____months from the date of issuance of license.
7. List here and attach copies of State water permits or other permits obtained authorizing the use or diversion of water, or the construction, and/or operation and maintenance of the proposed projects:
8. Attach an environmental report prepared in accordance with the requirements set forth in the *Instructions for Completing Application for Short-Form License.*
9. Attach Exhibit K and L drawings.
10. State of_____
County of_____ ss:
_____ and _____, being duly sworn, each for himself, deposes and says that *(he is a citizen of the United States of America), *(all members of the association are citizens and have signed this affidavit) or *(he is the duly appointed agent of the association, municipality or corporation), and has signed this application this _____ day of _____, 19____

_____
(Applicant(s))

By_____
Subscribed and sworn to before me, a Notary Public of the State of _____
this _____ day of _____, 19____

/SEAL/ _____
(Notary Public)

INSTRUCTIONS FOR COMPLETING APPLICATION FOR SHORT-FORM LICENSE

GENERAL

1. This application may be used if the proposed project will have a total generating capacity of not more than 1,500 kW, impound a reservoir having a surface area of not more than 10 acres, and include no dam or diversion structure over 25 feet in height. Advice regarding the proper procedure for filing should be requested from the Commission in Washington, D.C.; or from one of the Commission's regional offices in Atlanta, Chicago, Fort Worth, New York, or San Francisco.

2. This application is to be completed and filed in an original and nine copies with the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Each copy of the application is to be accompanied by:

(a) A copy each of exhibits K and L described herein.

(b) A copy of a State water quality certificate pursuant to section 401 of the Federal Water Pollution Control Act, and a water rights certificate or similar evidence required by State law relative to use or diversion of water.

(c) Applicant should contact the State natural resources department or equivalent to ascertain whether other approvals are necessary and attach copies of such approvals to the application.

(d) A copy of applicant's environmental report described herein.

3. No work may be started on the project until receipt of a signed license from the Commission. The application itself does not authorize entry upon government lands for any purpose. If the project is located in part or in whole upon Federal land, the applicant should contact the appropriate land management agency regarding the need to obtain a right-of-way permit. As noted above, other State or Federal permits may be required.

4. Applicants must be citizens of the United States. If the applicant is a corporation, the State in which it is incorporated and the location of the principal place of business must be shown. If applicant is an association, each member must be a citizen and must sign the affidavit. The affidavit may be attached as a separate sheet if necessary. Corporations (municipal or private), municipalities, and associations of citizens shall provide the name and address of the person who is authorized to act as agent, and consent to accept service upon such agent as service upon the applicant. This information can be provided by a letter attached to the application.

5. If the stream is unnamed, give the name of the nearest named stream to which it is tributary.

6. The project description (application item 4) shall include, as appropriate: The number of generating units, including auxiliary units, the capacity of each unit, and provisions, if any, for future units; type of hydraulic turbine(s); a description of how the plant is to be operated, manual or automatic, and whether the plant is to be used for peaking; estimated average annual generation in kilowatt-hours; estimated average head on the plant; reservoir surface area in acres; estimated hydraulic capacity of the plant (flow through the plant) in cubic feet per second; estimated average flow of the stream at the plant or point of diversion; sizes, capacities, and construction materials, as appropriate, of pipelines, ditches, flumes, canals, intake facilities, powerhouse, dams, transmission lines, etc.; and estimated cost of project.

7. In the case of unsurveyed public land, or land not in a public-lands State, give the best legal description available. Include the distance and general direction from the nearest city or town, fixed monument, physical features, etc.

8. Exhibits K and L shall be submitted on separate drawings. Drawings for exhibits K and L shall have identifying title blocks and bear the following certification: "This drawing is a part of the application for license made by the undersigned this ____ day of _____, 19____

_____"

(Name of applicant.)

9. The Commission reserves the right to require additional information, or another filing procedure if data provided indicate such action to be appropriate.

Exhibit K—Project Lands and Boundaries

1. The exhibit K is a planimetric map showing the portion of the stream developed, the location of all essential project information; such as the dam or diversion structure, pipeline, powerplant, access roads, transmission lines, project boundary, land ownerships, and government land boundaries and identifications.

2. The map shall be an ink drawing or drawing of similar quality on a sheet not smaller than 8 inches by 10 ½ inches, drawn to a scale no smaller than 1 inch equals 1,000 feet. Ten legible prints shall be submitted with the application. The tracing will be requested after review of the application.

3. The project boundary shall be drawn on the map so that the relationship of each project facility to other property lines can be determined. The boundary shall enclose all project works such as the pipelines, roads, powerhouse, and transmission lines. It shall be the minimum feasible distance from project works necessary to allow operation and maintenance. The distance in feet from each principal facility to the boundary shall be shown. The project boundary should be a surveyed line with stated courses and distances. A tape-compass survey is acceptable. True north shall be indicated on the map. The area of government land in acres within the project boundary shall be shown. It is suggested that the appropriate government agency be contacted for assistance in determining the government land acreage. For clarity, use inset sketches to a larger scale than that used for the overall map to show relationships of project works, natural features, and property lines.

4. Show one or more ties by distance and bearing from a definite, identifiable point or points on project work or the project boundary to established corners of the public land survey or other survey monuments, if available.

5. If the project affects unsurveyed government lands, the protraction of township and section lines shall be shown. Such protractions, whenever available, shall be those recognized by the agency of the United States having jurisdiction over the lands. On unsurveyed lands, show ties by distance and bearing to fixed recognizable objects.

6. If both government and private lands are utilized by the project, the detailed survey descriptions discussed above for the project boundary apply only to government lands. General location data will suffice for project works on private lands.

EXHIBIT L—PROJECT STRUCTURES AND EQUIPMENT

1. The exhibit shall be a simple ink drawing or drawing of similar quality on a sheet not smaller than 8 inches by 10 ½ inches, drawn to a scale no smaller than 1 inch equals 50 feet for plans and profiles, and 1 inch equals 10 feet for sections. Ten legible prints shall be submitted with the application. Tracing(s) will be requested after initial review of the application.

2. The drawing shall show a plan, elevation, and section of the diversion structure and powerplant. Generating and auxiliary equipment proposed should be clearly and simply depicted and described. Include a north arrow on the plan view.

ENVIRONMENTAL REPORT

The requirement herein for an environmental report should be consistent with the scope of the project and the environmental impacts of the proposed action, i.e., authorization to operate and maintain an existing project would require less detailed information than authorization to construct a new project. The environmental report shall set forth the following in a clear and concise manner:

(1) A brief description of the project and the mode of operation, i.e., run-of-river, peaking, or other.

(2) A description of the environmental setting in and near the project area to include vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational use, socioeconomic aspects, historical and archeological resources, and visual resources. Special attention shall be provided rare and endangered plant and animal species, critical habitats, sites eligible for or included on the National Register of Historic Places. Assistance in the preparation of this information may be obtained from state natural resources departments.

(3) A description of the expected environmental impacts resulting from construction and operation of the project. Include a discussion of specific measures proposed by the applicant or others to protect and enhance environmental resources and to mitigate adverse impacts of the project on the environmental resources and values, and the cost thereof.

(4) A description of alternative means of obtaining an amount of electric power equivalent to that provided by the project in the event that construction or continued operation of the project is not authorized.

(5) A description of the steps taken by the Applicant in consulting with Federal, State, and local agencies during the preparation of the environmental report. Indicate which agencies have received the final report and provide copies of letters containing the comments of those agencies.

PART 2—GENERAL POLICY AND INTERPRETATIONS

4. The Commission proposes to amend Part 2, Subchapter A—General Rules, Chapter I, Title 18, Code of Federal Regulations, by adding two new L-Forms, L-22, and L-23, to the end of § 2.9(c).

As amended, § 2.9(c) will read:

§ 2.9 Conditions in preliminary permits and licenses—list of and citations to "P-" and "L-" Forms.

* * * * *

(c)* * *

P-1: * * *

L-22: Short-Form License, Projects Affecting Lands of the United States, 57 FPC—(April, 1978).

L-23: Short-Form License, Projects Not Affecting Lands of the United States, 57 FPC—(April, 1978).

B. Proposed new L-Forms L-22 and L-23 are attached to this Notice of Proposed Rulemaking as Appendix A and Appendix B respectively.

C. Any interested person may submit to the Federal Energy Regulatory Com-

mission, Washington, D.C. 20426, not later than May 23, 1978, data, views, comments or suggestions in writing concerning all or part of the amendments proposed herein. Written submittals will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, 825 North Capitol Street, Washington, D.C. 20426 during regular business hours. The Commission will consider all such written submittals before acting on the matters herein proposed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Submittals to the Commission should indicate the name, title, and mailing address of the person to whom communications concerning the proposal should be addressed and whether the person filing them requests a conference with the staff of the Commission to discuss the proposed amendments. The staff, in its descretion, may grant or deny requests for conferences.

D. The Secretary shall cause prompt publication of this notice to be made in the FEDERAL REGISTER.

By Direction of the Commission.

KENNETH F. PLUMB,
Secretary.

APPENDIX A

FEDERAL ENERGY REGULATORY COMMISSION

Form L-22 (April, 1978)

SHORT FORM LICENSE

Projects Affecting Lands of the United States

Project No. _____

An application was filed on _____ and supplemented on ____ by_____ for a short form license for a hydroelectric project located on lands of the United States_____

Order issuing short form license:

Date of issuance:_____

(A) This license is issued to _____ (Licensee) of _____, for a period effective the first day of the month in which this order is issued, and terminating ____ years thereafter, for the construction and/or operation and maintenance of Project No. ____ located on _____, a tributary of the _____, affecting lands of the United States under the administration of _____, subject to the terms and conditions of the Federal Power Act, insofar as not expressly waived herein, which Act is incorporated by reference as part of this license and subject to such rules and regulations as the Commission has issued or prescribed under the provisions of the Act.

(B) This project consists of:

(i) all lands constituting the project are and enclosed by the project boundary or the Licensee's interests in such lands, the limits of which are otherwise defined, the use and occupancy of which are necessary for the purpose of the project; such project area and project boundary being shown and described by certain Exhibit K drawing(s), FERC No(s)_____, which also form part of the application for license.

(ii) project works consisting of;

the location, nature, and character of which are more specifically shown and described by the exhibit hereinbefore cited and by Exhibit L drawing(s), FERC NO(s). _____, which also form part of the application for license.

(iii) all of the structures, fixtures, equipment, or facilities used or useful in the maintenance and operation of the project and located on the project area, and such other property as may be used or useful in connection with the project or any part thereof; together with all riparian or other rights, the use or possession of which are necessary or appropriate in the maintenance or operation of the project.

The exhibits designated and described in the above paragraphs are hereby approved and made a part of the license.

¶ 31,990 Procedures for Review by Federal Energy Regulatory Commission of Remedial Orders Issued by Secretary of Energy

43 F.R. 19669 (May 8, 1978).

[18 CFR Part 1]

[Docket No. RM78-10]

PROCEDURES FOR REVIEW BY FEDERAL ENERGY REGULATORY COMMISSION OF REMEDIAL ORDERS ISSUED BY SECRETARY OF ENERGY

Proposed Rulemaking and Public Hearing

MAY 2, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: The Federal Energy Regulatory Commission (the Commission) gives notice of a proposal to establish regulations governing procedures for Commission review of remedial orders issued by the Secretary of Energy (the Secretary) pursuant to the Emergency Petroleum Allocation Act of 1973 (Pub. L. 93-159), as amended (the EPAA). Authority to review remedial orders of the Secretary was conferred upon the Commission by section 503 of the Department of Energy Organization Act, Pub. L. 95-91 (the Act).

DATES: Written comments by June 5, 1978; requests to speak by May 19, 1978; statements by May 24, 1978; public hearing to be held at 9:30 a.m., May 25, 1978, to be continued the following day if necessary.

ADDRESSES: Written comments, requests to speak and statements should reference Docket No. RM78-10 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. The public hearing will be held at the same location in hearing room A.

FOR FURTHER INFORMATION CONTACT:

Mary Wright, Assistant General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Room 8200, Washington, D.C. 20426, 202-275-4273.

Bonnie Cord, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 8200, Washington, D.C. 20426, 202-275-4210.

SUPPLEMENTARY INFORMATION:

A. BACKGROUND

Section 503(a) of the Department of Energy Act (Pub. L. 95-91) (the Act), provides that if upon investigation, the Secretary of Energy (Secretary) or his authorized representative believes that a person, including any individual, association, company, corporation, partnership or other entity, has violated any regulation, rule or order issued pursuant to the Emergency Petroleum Allocation Act of 1973 (Pub. L. 93-159, as amended) (EPAA), he may issue a remedial order to that person. Section 503(b) of the Act provides that the remedial order will become effective 30 days after receipt unless the recipient notifies the Secretary that he intends to contest the order.

Under section 503(c), if the Secretary receives notice that the order will be contested the Secretary must notify the Commission immediately, and the Commission is required to stay the effect of the remedial order unless it finds that the public interest requires immediate compliance. Section 503(c) further states:

The Commission shall, upon request, afford an opportunity for a hearing, including, at a minimum, the submission of briefs, oral or documentary evidence, and oral arguments. To the extent that the Commission in its discretion determined that such is required for a full and true disclosure of the facts, the Commission shall afford the right of cross-examination. The Commission shall thereafter issue an order, based on findings of fact, affirming, modifying, or vacating the Secretary's remedial order, or directing other appropriate relief, and such order shall, for the purpose of judicial review, constitute a final agency action, except that enforcement and other judicial review of such action shall be the responsibility of the Secretary.

The Statement of Managers accompanying the Conference Report on the Act states that responsibility to review remedial orders was placed in the Commission

rather than elsewhere in the Department to assure that the Department's review of any initial action taken with respect to remedial orders will be by officials who were in no way involved in the Department's original action. The Conferees stated that this would guarantee a separation of the Department's prosecutorial and judicial functions relating to enforcement. The Conferees also emphasized that the procedures specified in the Act" for review of remedial orders—

* * * are intended to clearly reaffirm the intent of Congress that those involved in enforcement actions * * * be extended procedural due process. Congress always intended that the notions of fair play and due process be followed in the administrative process. (S. Rep. No. 95-367, 95th Cong. 1st Sess. 85-86 (1977)).

On January 6, 1978, the Economic Regulatory Administration (ERA) issued proposed regulations, effective immediately on an interim basis (43 FR 1930, January 13, 1978) relating to the procedures that it would follow in issuing remedial orders under the EPAA.

By notice issued March 15, 1978, (43 FR 13073, March 29, 1978), ERA extended the date for filing comments to May 10, 1978, and scheduled a public hearing on the proposals for May 3, 1978. The regulations proposed by ERA provide generally for issuance by the Special Counsel for Compliance or the Assistant Administrator for Enforcement of a proposed remedial order, followed by an opportunity for aggrieved or interested parties to present evidence before the ERA's Office of Administrative Review relative to the proposed remedial order prior to issuance of the remedial order in final form. Under ERA's proposal, evidentiary hearings could be convened where appropriate, and an opportunity for oral argument would be afforded as a matter of right. The proposed regulations would also apply to interim remedial orders for immediate compliance and orders of disallowance, prohibit ex parte communications and authorize the issuance of ancillary orders. Since the proposal was issued, the Department has announced that that Office's functions will be transferred to a new Office of Hearing and Appeals (OHA) independent of ERA. Thus, under the Department's new announced organization, final remedial orders will be issued by OHA rather than by an office within ERA.

Since the proposed and interim regulations of the Department will to some extent affect the nature of the proceedings to be conducted by the Commission, the Commission invites interested persons to consider these regulations in connection with the Commission's proposed review procedures.

B. Summary of the Commission's Proposed Regulations.

The procedures proposed by the Commission for its review of remedial orders are intended to provide a full and fair consideration of the contested issues in relation to the order without imposing in any case procedural requirements which are unnecessary or unduly burdensome. Thus, the Commission anticipates that where necessary to provide a full and fair disclosure of the facts, an evidentiary hearing will be held, including the right of cross-examination, but that in some cases, disputed issues will be resolved on the basis of written submissions. Whenever a party to a proceeding requests an oral hearing with submissions of briefs, oral or documentary evidence and oral arguments, the request will be granted, as provided in section 503(c) of the Act.

Request for Confidential Treatment. Proposed §1.38(c) of 18 CFR Part 1, Rules of Practice and Procedure of the Federal Energy Regulatory Commission, provides that information filed by a person under this section may be withheld from public disclosure if the person: (1) Claims that the material is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt from public disclosure; (2) requests the Presiding Officer not to disclose the information; (3) serves the requests on other participants in the proceeding; (4) submits a copy of the document concerned with alleged confidential information deleted; (5) indicates on the original document that confidentially is claimed; and (6) includes a statement justifying the confidentiality claim, if the claim is made pursuant to the trade secret and commercial or financial information exemption of 5 U.S.C. 552(b)(4). If the second copy with deletions is not

submitted, the Presiding Officer may assume that there is no objection to public disclosure. The Presiding Officer shall notify a person of the denial of a claim and provide an opportunity to respond at least 5 days prior to public disclosure of the information. Other participants may oppose the request by filing, within 10 days of receiving a copy of the request, a statement specifying the reasons that the material should not be considered confidential. The Presiding Officer shall notify all participants of his determination as to the claimed confidentiality. If he finds that the information is confidential, the Presiding Officer shall, upon request, determine whether the information may be released to participants, upon request, and shall notify all participants of this determination.

The Commission particularly invites comments on the provisions of the proposal relating to confidentiality including the method by which presiding officers make the determinations of confidentiality. The possibility that a decision may be based on information contained in documents which other parties cannot contest because the information has been determined to be confidential is disturbing. However, the possibility of requiring parties to risk disclosing trade secrets or sensitive financial data to competitors in order to defend themselves in actions before the Commission also present problems. The Commission intends to consider a broad range of approaches to this matter, including refusing to classify any documents as confidential if it supports a material fact in the case and is contested. Accordingly, commentors are encouraged to submit alternative provisions governing confidentiality, and should consider this proposal merely as a description of the subject of this portion of the rule and the issues involved in it.

Commencement of Proceedings. Proposed § 1.38(d) provides that proceedings under this section are commenced by written notice to the Commission by the Secretary of Energy or his delegate that he has been notified by the recipient of an order (the petitioner) that the order will be contested. The proceedings are also commenced by the petitioner's filing a notice of appeal of the denial of an application for stay of an interim remedial order pursuant to 10 CFR 205.199(D)(i)(2). The contested order may be a remedial order under 10 CFR 205.199, an interim remedial order for immediate compliance under 10 CFR 205.199D or an order of disallowance under 10 CFR 205.199E. Upon notice from the Secretary or upon the receipt of the notice of appeal from the petitioner under proposed § 1.38(d), the Presiding Officer would be designated by the Commission or its designee for the proceeding. In this regard, the Commission requests the views of interested parties as to whom it should appoint as Presiding Officer in these proceedings, and as to the type of qualifications or experience that would be realistic and desirable for Presiding Officers in view of the Commission's resources.

Stay of Contested Order. Proposed § 1.38(e) provides that upon filing of the notice by the Secretary under paragraph (d) the contested order is automatically stayed unless the Presiding Officer finds on its own motion or upon request of the Secretary or other participant that the public interest requires immediate compliance with the contested order. A request not granted within 10 days would be denied. The Presiding Officer could extend the time for a determination for up to 7 days. The Presiding Officer will notify petitioner of any denial of a request, and such denial may be appealed to the Commission under § 1.28, except that if the Commission has not acted upon the appeal within 20 days of the filing of the appeal, the appeal shall be deemed to have been denied.

Pleadings. Within 20 days after service of notice by the Secretary under paragraph (d), the Secretary must file with the Presiding Officer and serve upon other participants a copy of the contested order and must certify to the Presiding Officer the complete record developed in the proceedings before the Secretary. In addition, the Secretary may elect to file a separate brief setting forth the elements of the alleged violation with a statement of the factual and legal basis of the contested order, which would also have to be filed with the Presiding Officer within 20 days and served on other participants.

The petitioner's reply, which is due within 20 days of service of the Secretary's pleadings and which the petitioner must serve on all participants in the proceeding, would be required to state fully the petitioner's objections, supported by

arguments, to the legal and factual basis of the contested order. New facts or issues could be raised in accordance with the proposed § 1.38(f)(2)(ii). In this regard, the Commission would not review an order otherwise reviewable under this section which was issued without underlying evidentiary proceedings. If in the proceeding before OHA the recipient did not reply to a notice of probable violation or file a notice of objection to a proposed remedial order, a final remedial order could be issued on the basis of the recipient's "consent" without ERA's proving its affirmative case for the record. Thus, any facts or issues raised by the recipient before the Commission would be new facts or issues which would not satisfy the criteria of § 1.38(f)(2)(ii)(A).

Within 20 days from the service of the petitioner's reply, the Secretary may file a response to the petitioner's objections and supporting arguments, which response the Secretary must serve on all participants.

Any person denied the opportunity to participate in prior proceedings could petition to intervene, in accordance with § 1.8. In order that the petition be granted, the person must establish that the denial of opportunity to participate in prior proceedings was wrongful. If the petition were granted, the person could then file briefs as determined by the Presiding Officer.

The time for filing pleadings could be extended for good cause as provided in § 1.13(d).

Hearings. Proposed § 1.38(g)(1) states that any participant may, at a time or times specified by the Presiding Officer, request an opportunity for hearing, which shall be granted. The Presiding Officer may on his own motion convene a hearing. The Presiding Officer, on his motion or on the motion of a participant, could order that there be an opportunity for cross-examination if necessary for a full and true disclosure of the facts. Proposed § 1.38 also provides that the Presiding Officer shall give notice to all participants of the time and place of the hearing. That section also states that the Presiding Officer shall determine the issues to be resolved in the proceeding, may specify the time available for oral argument, and may convene a prehearing conference to determine the issues or the nature of the proceeding to be held.

The Presiding Officer would determine the order of procedure at the hearing, except that in every case, the Secretary has the burden of proof regarding all disputed elements of the affirmative case. Other matters relating to the conduct of the hearing are to be determined by the Presiding Officer. At the conclusion of the hearing an opportunity is provided for participants to submit proposed findings of fact and conclusions of law, and replies thereto, with the requirement that participants serve all such submissions on all other participants.

Order. Proposed § 1.38(i) provides that the Presiding Officer issue a proposed order affirming, modifying or vacating the contested order or directing other appropriate relief. The proposed order and a copy of the record would then be certified and filed with the Commission. A final order affirming, modifying or vacating the contested order or directing other appropriate relief issued by the Commission and served on all participants would constitute a final agency action for purposes of judicial review.

Ex parte communications. Proposed § 1.38(k) provides that the ex parte provisions of § 1.4(d) of this subpart apply to proceedings under this section as if such proceedings were contest on-the-record proceedings pending before the Commission.

Other Issues. The Commission requests comments not only on these proposed procedures, but also on suitable alternatives thereto and on any other issues which interested persons believe it should consider in this rulemaking proceeding.

C. Written Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to June 5, 1978, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the

Commission's Office of Public Information, 825 North Capitol Street NE., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM78-10.

D. Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on May 25, 1978, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on May 19, 1978.

Requests to participate in the hearing should include a reference to Docket No. RM78-10, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing each person filing a request to participate will be contacted by the Presiding Officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4 p.m., on May 24, 1978. The Presiding Officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the Presiding Officer to be asked of persons making statements. The Presiding Officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the Presiding Officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267).

In consideration of the foregoing, it is proposed to amend Part I, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

LOIS D. CASHELL,

Acting Secretary.

1. Part 1, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended in the table of contents by adding in the appropriate numerical order a new section number and heading to read as follows:

PART 1—RULES OF PRACTICE AND PROCEDURE

* * * * *

Sec. 1.38 Commission Review of Remedial Orders.

* * * * *

2. Part 1, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended in the Statement of Authority by inserting between "825h," and "unless otherwise noted" a phrase to read as follows:

AUTHORITY: 42 U.S.C. 7193(c), E.O. 12009, 42 FR 46467. * * *

3. Part 1, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended by adding a new § 1.38, to read as follows:

§ 1.38 Commission review of remedial orders.

(a) *Scope.* (1) The provisions of this section shall apply to proceedings of the Commission held in accordance with section 503(c) of the Department of Energy Organization Act, Pub. L. 95-91, 42 U.S.C. 7913(c), to review orders issued by the Secretary of Energy pursuant to section 503(a) of the Department of Energy Organization Act, and initiated by notices of probable violation issued on or after October 1, 1977, which are contested by the recipient.

(2) Except as otherwise specifically provided in this section, the following

provisions of the Part shall apply to proceedings under this section:

(i) § 1.1—The Commission;

(ii) § 1.2—The Secretary;

(iii) § 1.3—Notice of public sessions and proceedings;

(iv) § 1.4—Appearances and practice before the Commission;

(v) § 1.8—Intervention (except for paragraph (b));

(vi) § 1.11—Amendments and withdrawal of pleadings;

(vii) § 1.12—Motions;

(viii) § 1.13—Time, extensions of time, issuance of orders;

(ix) § 1.14—Filings, docket; hearing calendar;

(x) § 1.15—Formal requirements as to pleadings, documents and other papers filed in proceedings;

(xi) § 1.16—Subscription and verification;

(xii) § 1.17—Service;

(xiii) § 1.21—Copies of transcripts;

(xiv) § 1.22—Witnesses;

(xv) § 1.23—Subpoenas;

(xvi) § 1.24—Depositions;

(xvii) § 1.25—Stipulations;

(xviii) § 1.26—Evidence;

(xix) § 1.27—Presiding officers;

(xx) § 1.36—Public information and requests; and

(xxi) § 1.51—Certificate of service.

(b) *Definitions.* For purposes of this section—

"Commission" means the Federal Energy Regulatory Commission.

"Contested order" means the remedial order, interim remedial order for immediate compliance, or order of disallowance being contested in a proceeding pursuant to this section.

"Interim remedial order for immediate compliance" means an interim remedial order for immediate compliance issued pursuant to 10 CFR 205.199D.

"Order of disallowance" means an order of disallowance issued pursuant to 10 CFR 205.199E.

"Participant" means, as appropriate, the Secretary, the petitioner, other interested persons who participated in prior proceedings on the contested order, and intervenors.

"Person" means any individual, association, company, corporation, partnership, or other entity however organized.

"Petitioner" means a person who has received a remedial order, interim remedial order for immediate compliance, or order of disallowance who notifies the Secretary that he intends to contest the order.

"Remedial order" means a remedial order issued pursuant to 10 CFR 205.199B.

"Secretary" means the Secretary of Energy or his delegate.

(c) *Request for confidential treatment.* (1) If any person filing under this section claims that some or all of the information contained in a document is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt by law from public disclosure, and if the person requests the Presiding Officer not to disclose such information, which request the person shall serve upon all participants in the proceeding, the person shall file together with the document a second copy of the document from which has been deleted the information for which the person wishes to claim confidential treatment. The person shall indicate in the original document that it is confidential or contains confidential information and may file a statement specifying the justification for nondisclosure of the information for which confidential treatment is claimed. If the person states that the information comes within the exception in 5 U.S.C. 552(b)(4) for trade secrets and commercial or financial information, the person shall include a statement specifying why the information is privileged or confidential. If the person filing a document does not submit a second copy of the document with the confidential information deleted, the Presiding Officer may assume that there is no objection to public disclosure of the document in its entirety. The Presiding Officer retains the right to make his own determination with regard to any claim of confidentiality. Notice of the decision by

the Presiding Officer to deny a claim, in whole or in part, and an opportunity to respond shall be given to a person claiming confidentiality of information no less than 5 days prior to its public disclosure.

(2) A participant in the proceeding who wishes to oppose a request for confidential treatment under subparagraph (1) of this paragraph shall, within ten days of the receipt of a copy of the request, file with the Presiding Officer and serve on other participants a statement specifying the reasons that the material is not confidential or priviledged. The Presiding Officer shall notify all participants of his determination as to confidentiality. If the Presiding Officer determines that the material is confidential, he shall, upon request by a participant, determine whether the information may be released, upon request, to participants and shall notify all participants of his determination.

(d) *Commencement of proceedings.* (1) Except as provided in subparagraph (2) of this paragraph, proceedings pursuant to this section shall be commenced by written notice to the Commission by the Secretary that he has been notified by a petitioner that the petitioner intends to contest an order reviewable under this section. At the same time, the Secretary shall certify to the Commission that he has served such written notice upon other participants in the prior proceedings and upon persons denied intervention in the prior proceedings.

(2) Proceedings pursuant to this section with respect to an interim remedial order for immediate compliance shall be commenced by a petitioner's filing, with the Commission, a notice of appeal from the denial of an application for a stay of an interim remedial order for immediate compliance pursuant to 10 CFR 205.199(D)(i)(1).

(3) Upon receipt of notice from the Secretary under subparagraph (1) of this paragraph, or upon receipt of a notice of appeal by the petitioner under subparagraph (2) of this paragraph, the Commission or its designee shall designate a Presiding Officer for the proceeding and shall notify participants in the prior proceeding and persons denied intervention in the prior proceedings of such designation.

(e) *Stay of contested order.* (1) Upon the filing with the Commission by the Secretary of the notice under paragraph (d) of this section, the contested order shall be automatically stayed pending review pursuant to this section unless the Presiding Officer finds that the public interest requires immediate compliance with the contested order.

(2) The Secretary or other participant may at any time prior to the hearing under paragraph (g) of this section or if there is no hearing, prior to the issuance of a proposed order under paragraph (i) of this section, file a petition requesting that the contested order not be stayed and setting forth the legal and factual basis for the request.

(3) The Presiding Officer may request a written statement of the views of any participant regarding whether the contested order should not be stayed, and may convene an expedited hearing or conference on a petition under subparagraph (2) of this paragraph.

(4) The Presiding Officer may grant the petition requesting immediate compliance where he finds that the public interest requires immediate compliance.

(5) If the Presiding Officer has not granted the petition under subparagraph (2) of this paragraph within 10 days after it is filed, the petition shall be deemed denied. Prior to the expiration of the 10 day period the Presiding Officer may extend the period for decision for up to 7 days. At the end of the extension the petition, if not granted, shall be deemed denied.

(6) If the petition under subparagrph (2) of this paragraph is denied, the Presiding Officer shall notify petitioner of such denial.

(7) A grant or denial of a petition under subparagraph (2) of this paragraph may be appealed to the Commission in accordance with § 1.28, except that unless the Commission acts upon the appeal within 20 days after the filing of the appeal, the appeal shall be deemed to have been denied. The contested order will be automatically stayed pending the Commission's disposition of the appeal.

(f) *Pleadings.*—(1) *By the Secretary.* (i) Within 20 days after service of notice by the Secretary under paragraph (d), the Secretary:

(A) Shall file with the Presiding Officer a certified copy of the complete record de-

veloped in prior proceedings on the contested order, which shall be deemed a part of the record upon which the order of the Commission is based, and which shall be available at the Commission for inspection by the participants;

(B) Shall file with the Presiding Officer and serve on the other participants in the proceeding a copy of the contested order; and

(C) May, in addition, elect to file a brief in support of the affirmative case, which brief must set forth: (*1*) The elements of the alleged violation, including references to all authorities upon which the Secretary relies, including but not limited to regulations, rulings, interpretations and decisions on appeals and exceptions issued by the Department or its predecessor agencies, and precedents established by the Commission; and (*2*) a complete statement of the factual and legal basis of the contested order. The Secretary shall serve the brief on all participants in the proceedings.

(ii) With 20 days after service of the petitioner's reply, the Secretary may file with the Presiding Officer and serve upon other participants in the proceeding a response to the petitioner's reply.

(*2*) *By the petitioner.* (i) Within 20 days after service by the Secretary under subparagraph (1) of this paragraph, the petitioner shall file with the Presiding Officer and serve upon the Secretary and other participants in the proceeding a reply stating fully the objections, supported by arguments, to the factual and legal basis of the contested order.

(ii) In the reply, the petitioner may also request permission to raise new facts or issues not raised in prior proceedings on the contested order that (A)(*1*), are new facts or issues that were not known and could not, with the exercise of due care, have been known to the petitioner at the time they could have been raised during prior proceedings; or (*2*) are facts or issues that the petitioner was not permitted to raise due to adverse procedural rulings alleged to be erroneous in prior proceedings on the contested order; and (B) are necessary for a full and true disclosure of the facts.

(3) *By other persons.* Any other person who participated in prior proceedings on the contested order may participate in proceedings under this section and may make filings and submittals as determined by the Presiding Officer.

(4) *By intervenors.* Any person who was denied the opportunity to participate in prior proceedings on the contested order may petition the Presiding Officer to intervene in proceedings under this section in accordance with § 1.8. In order that the petition be granted, petitioner must show that denial of participation in prior proceedings was wrongful. If the Presiding Officer grants the petition, the petitioner may make filings and submittals as determined by the Presiding Officer.

(g) *Hearings.* (1) Any participant may, at such time or times as specified by the Presiding Officer, file a request for an opportunity for hearing or a motion for the opportunity for cross-examination including the reasons why cross-examination is necessary for a full and true disclosure of the facts.

(2) If a participant has filed a request for opportunity for hearing, the Presiding Officer shall grant the request for opportunity for hearing, which will include, at a minimum, the submission of oral or documentary evidence and oral arguments.

(3) The Presiding Officer may at any time, on his own motion, convene a hearing before the Presiding Officer.

(4) If at any time prior to the issuance of a proposed order pursuant to paragraph (i) of this section, upon motion of any participant or on his own motion, the Presiding Officer in his discretion determines that it is necessary for a full and true disclosure of the facts, he may order that the participants be afforded the opportunity for cross-examination on any facts or issues raised in the proceedings, on disputed portions of the record from prior proceedings, or, if determined under paragraph (f)(*2*)(ii) of this section, on new facts or issues.

(5) As soon as practicable after receiving the pleadings under paragraph (f) of this section, the Presiding Officer shall give notice to all participants of the time and place of the hearing.

(6) The Presiding Officer shall determine the issues to be resolved in the proceeding, may specify the time available for oral argument, and shall give notice thereof to the participants. The Presiding Officer may require additional informa-

tion from the participants and may convene a prehearing conference for the purpose of determining the issues or the nature of the proceeding to be held.

(h) *Conduct of the hearing.* (1) The order of procedure at the hearing shall be determined by the Presiding Officer, except that the Secretary shall have the burden of proof with respect to all disputed elements of his affirmative case.

(2) The Presiding Officer shall be responsible for the conduct of the hearing.

(3) Within 10 days after the conclusion of the hearing, any participant may file with the Presiding Officer and serve upon the other participants proposed findings of fact and conclusions of law, a brief in support thereof and any objections with respect to the treatment of confidential information under paragraph (c)(2) of this section or a denial of a motion for an opportunity for cross-examination.

(4) Within 5 days after service of proposed findings of fact and conclusions of law under subparagraph (3) of this paragraph any participant may file, and shall serve on other participants, a reply thereto.

(i) *Proposed order.* (1) After the conclusion of the hearing and after the filing of briefs pursuant to paragraph (h)(3) and (4) of this section, the Presiding Officer shall issue a decision and proposed order based on findings of fact affirming, modifying, or vacating the contested order or directing other appropriate relief. The proposed order shall be based on the entire record before the Presiding Officer, including the record at prior proceedings certified by the Secretary, and shall be based on a preponderance of the evidence.

(2) The Presiding Officer shall certify and file with the Secretary of the Commission, for the Commission, a copy of the record on the hearing, including the proposed order.

(j) *Commission action.* The Commission shall upon consideration of the entire record and the proposed order issue a final order affirming, modifying, or vacating the contested order or directing other appropriate relief. The Commission shall serve the final order on all participants.

(k) *Ex parte communications.* The provisions of § 1.4(d) shall apply to proceedings pursuant to this section, commencing at the time the Secretary gives notice under paragraph (d)(1) of this section, as if such proceedings were contested on-the-record proceedings pending before the Commission.

¶ 31,991 Incentive Rate of Return for the Alaska Natural Gas Transportation System

43 F.R. 20241 (May 11, 1978).

[18 CFR Chapter 1]

[Docket No. RM78-12]

INCENTIVE RATE OF RETURN FOR THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Proposed Rulemaking

MAY 8, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: The Federal Energy Regulatory Commission (the Commission) hereby gives notice of a proposal to establish certain terms and conditions to the conditional certificates of public convenience and necessity previously issued in the Alaska Natural Gas Transportation System proceeding. The proposed terms and conditions would establish an incentive rate of return on equity to reward the applicants for final certificates for project completion under budgeted cost and penalize them for project completion over budgeted cost.

DATES: Notices of intention to participate by May 19, 1978; written comments by May 31, 1978; reply comments by June 9, 1978.

ADDRESSES: All filings should reference Docket No. RM78-12 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

John Adger, Director, Alaska Natural Gas Project Office, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-3827.

SUPPLEMENTARY INFORMATION: Notice is hereby given, pursuant to the Administrative Procedure Act, 5 U.S.C. section 552, the Natural Gas Act, sections 4, 5, 7, and 16 (15 U.S.C. secs. 717c, 717d, 717f, and 717o), and the Alaska Natural Gas Transportation Act, section 9 (15 U.S.C. sec. 719g), that the Federal Energy Regulatory Commission is considering the adoption of terms and conditions concerning an incentive rate of return on equity on the conditional certificates of public convenience and necessity for the Alaska National Gas Transportation System, issued by the Commission on December 16, 1977 (*Alcan Pipeline Company, et al.*, Docket Nos. CP78-123, CP78-124 and CP78-125).

A. BACKGROUND

The President's "Decision and Report to Congress on the Alaska Natural Gas Transportation System" (the Decision) transmitted to the Congress on September 22, 1977, and approved by both Houses on November 2, 1977, states in the second finance term and condition on pages 36-37 that this Commission shall fix a variable rate of return on equity that will reward the applicant for project completion under budgeted cost and penalize the applicant for project completion over budgeted cost. The Decision also states that the final capital cost estimates filed with this Commission prior to the issuance of a final certificate of public convenience and necessity will be used as the basis for determining the variable rate of return on equity. If final cost estimates materially and unreasonably exceed the comparable capital cost estimates filed by Alcan with the Federal Power Commission on March 8, 1977, this Commission may determine that a certificate should not be issued for the project.

A specific proposal for implementing these conditions of the President's Decision is presented here in the form of a proposed rule. The Commission seeks comments of interested parties on the Commission's proposals and alternatives for a variable rate of return on equity mechanism. In this rulemaking, specific values are not given for a number of key parameters or schedules. This will be done in future rulemakings or orders, but the Commission solicits comments and opinions as to the appropriate values.

B. DISCUSSION OF THE PROPOSED TERMS AND CONDITIONS

The proposed terms and conditions describe a mechanism to implement the proposal in the President's Decision that the equity investors in the Alaska Natural Gas Transportation System be rewarded

for completing the project for less than estimated construction costs and penalized for cost overruns. The basic approach is to lower the return on equity during operation as the actual rate base increases relative to the projected rate base. However, incentive rates of return would not actually be employed to calculate the cost of service. Instead, an adjustment to the rate base would be made which is equivalent to the difference between the incentive rate and a normal rate. This rulemaking does not specify a schedule or formula for determining the rate of return for each level of cost control performance; specification of these parameters will be the subject of a subsequent proceeding.

The measure of cost control performance used to establish the variable rate of return will be a cost performance ratio that is described in condition 1. This is the ratio of the conventional or normal rate base to the projected rate base. Condition 2 specifies how the conventional rate base will be calculated; and condition 3 specifies how the projected rate base will be calculated. The projected rate base will be derived from the final capital cost estimate submitted by the applicant, and reviewed by the Commission, after adjustment for inflation and for changes in cost that result from certain changes in scope of the project.

Condition 4 requires that the applicant submit its final cost estimate both in 1975 dollars and in current dollars. The final estimate must be submitted in a format to be specified by the Commission at a later date. Also the March 1977, estimate, referred to in finance condition 2 of the Decision (p. 36), must be resubmitted in the same format. The requirement of comparability in the two cost estimates is necessary so that the Commission can determine the extent to which the final cost estimate exceeds the March 1977, estimate. Condition 5 states that the applicant may submit a proposed format for the final cost estimate to the Commission prior to the submittal of the final cost estimate itself.

The final direct capital cost estimates submitted by the applicant and approved by the Commission will be adjusted for actual inflation experienced in the U.S. economy during the period of construction. This will be done by specifying cost or price indexes for each of the major cost categories in the cost estimate prior to final certification. Again, the applicant is invited to propose to the Commission a format for final cost or price indexes.

One of the most difficult issues in specifying an incentive or variable rate of return scheme is whether to hold the applicant responsible for all cost increases. The Commission believes that there is a limited number of changes in the scope of the basic design and configuration of the project for which the applicant should not be held accountable for purposes of calculating the incentive rate of return. Condition 7 lists those changes in scope, and the Commission invites suggestions for changes in that list. If any of the listed changes in scope occur during the construction of the pipeline, the applicant shall submit a revised final cost estimate that shows how the estimated cost would have been increased if the changes in scope were known before the final cost estimate was approved by the Commission.

The Commission anticipates that the Office of the Federal Inspector, established by ANGTA and elaborated in the Decision, will have a role in recommending that the Commission approve any change in scope which might be allowed. The Commission will provide by rule for that role after the Office of the Federal Inspector has been established.

As a result of the incentive rate of return scheme, equity investors in the Alaska Gas Pipeline Project may be allowed a rate of return on equity by the Commission that is substantially higher or lower than allowed for other gas pipelines. It could be higher because of outstanding performance in controlling costs, or lower because of poor performance in controlling costs. The Commission, however, believes that difficulties may result from an abnormally high or low return on equity extending over the 25-year or longer life of the project. Thus, a better alternative is to make a one-time adjustment to the rate base that to the equity investor is equivalent in present value to the higher or lower rate of return resulting from the incentive rate of return scheme. After making this one-time adjustment to the rate base, this Commission and future Commission would then allow a normal or conventional rate of return on the adjusted rate base that is

appropriate for the risks of this project and for the financial conditions at that time. Determination of the rate of return commensurate with the risks involved in this project will be the subject of subsequent Commission action.

Condition 11 specifies how the adjustment to the rate base shall be calculated. The procedure is demonstrated by the following example. Assume that the Commission has determined that the normal rate of return on equity should be 12 percent. This rate of return should then be used by the applicant to calculate both the projected rate base and the unadjusted conventional rate base that form the cost performance ratio. The actual rates of interest on debt experienced during the construction period will be used to calculate the interest component of the allowance for funds used during construction (AFUDC) in both the projected and conventional rate base.

Next, assume that because of superior cost control performance by the applicant, the incentive rate of return specified by the incentive schedule approved by the Commission is 15 percent. In other words, the allowed rate of return on equity has been increased by 300 basis points over the normal rate. Using the 15 percent rate of return, the next step is to project the return of and return on equity over the operating life of the project based upon the conventional rate base and a financing and capitalization plan approved by the Commission. A discounted cash flow calculation is then made to determine the present worth or present value of this time stream of cash flow to equity investors, assuming a discount rate equal to the normal rate of return on equity, or 12 percent. In this example, the present value total will be substantially greater than the equity capital account that would otherwise be assumed for calculating the cost of service of the pipeline. The proposal would require that this present value total shall be assumed to be the amount of equity investment in the equity capital account. Similarly, the total rate base assumed for the pipeline at the time of commissioning[1] will be increased by the difference between the present value total and the conventional or normal equity capital account.

The Commission has attempted to structure its proposal to make equity investors in this pipeline indifferent between this adjustment to the rate base or a rate of return on equity equal to the incentive rate. The Commission believes that the one-time rate base adjustment provides more certainty of reward or penalty to equity investors without prejudicing their future financial condition. We invite comments as to situations in which the equity investors would not be indifferent as between these two methods of reward and penalty for cost control performance.

We request suggestions concerning appropriate values for those parameters not specified in this notice of methodologies or procedures for determining just and reasonable values. Parameters for which values must be determined at a later date include: (1) Incentive rate of return schedule, (2) cost price indexes, (3) cost estimate format, and (4) normal rate of return. The Commission observes that different values of these parameters could be set for the three main segments of the system, i.e., the Alaska Pipeline, Northern Border, and the Western Leg.

C. Alternative Approach

In addition to the described above, the Commission considered an alternative approach to implementing the variable rate of return concept in the President's "Decision." The difference between the two is that the rate of return on equity during the construction period (the equity AFUDC rate) would be varied, rather than making a rate-base adjustment which is the present-value equivalent to the difference in equity return between that for an incentive rate of return and that for a normal rate of return.

The other features of the proposal would remain essentially unchanged. A conventional rate base would be calculated from actual construction costs using the normal rate of return on equity set by the Commission as the equity AFUDC rate. A projected rate base would be calculated from the final cost estimates submitted by the applicant after adjustment for inflation and changes in scope. From these, the cost performance ratio would be calculated.

In the alternative approach, a schedule relating the performance ratio and the allowed AFUDC equity rate would be specified by the Commission. Upon com-

missioning of the pipeline, this schedule would be used to determine the allowed AFUDC equity rate. The rate base would be recalculated using this new rate. Thereafter during the operating period of the pipeline, a normal rate of return on equity would be allowed for determining the cost of service. If the incentive AFUDC rate were higher than the normal rate, the rate base would increase, and vice-versa.

The Commission perceives two disadvantages of this alternative approach. The first is that there would be an undesirable reduction in the incentive to control cost overruns near the end of the construction period. At the beginning of construction, a cost overrun has two effects: It lowers the allowed AFUDC equity rate on the previous equity capital investment; additionally, the equity share of the cost overrun will also earn this lower rate for the entire construction period. If, on the other hand, the same cost overrun occurred at the very end of the construction period, only the first effect of the overrun would be experienced. The allowed equity AFUDC rate would be lowered on the already invested equity, but there would be no effect on the new equity to finance the cost overrun. This equity investment would almost immediately begin to earn the normal rate of return on equity instead of the incentive rate as the pipeline begins operations.

The second disadvantage is that the schedule relating cost performance to the AFUDC rate would have to provide a much broader range of rates of return in order to have the same incentive effect as the proposal of varying the rate of return during operation. This results from the fact that the AFUDC equity rate only applies during the three-to-five year construction period while the incentive rate during the operating period would apply for at least twenty years.

The following table presents an example that compares the incentive rate of return approach proposed in this rulemaking to the alternative of adjusting the AFUDC equity rate. The table gives a range of values for the incentive rate of return during operation and the equivalent values for the AFUDC equity rate that would produce the same rate base at the start of pipeline operations. This table uses as an example a purely hypothetical pipeline with direct construction costs of $614 million spread over three years. $116 million is spent the first year, $243 million the second year, and $255 million the third year. The normal rate of return on equity both during construction and operation is assumed to be 12 percent and the rate of interest on debt is assumed to be 10 percent.

The table demonstrates that the AFUDC equity rate must be increased or decreased by a large amount to have the same effect as a much smaller change in the equity rate during operation. An 18 percent return during operation is equivalent to a 40.2 percent AFUDC rate when compared to the normal rate of 12 percent. For rates of return during operation below a level of approximately 10 percent, the equivalent AFUDC rate of return is negative, resulting in a negative AFUDC on equity. A 6 percent return during operation is equivalent to a 36 percent AFUDC rate in this hypothetical example.

The major advantage of the alternative, however, is that no new procedure would be required for adjusting the rate base as is used in the incentive rate of return approach in the proposed terms and conditions. Adjusting the equity AFUDC rate automatically adjusts the rate base.

Comparison of incentive role of return (ROR) methods

Variable equity ROR during operation				Variable equity ROR during construction		
Equity ROR	Present value of equity cash flow	Adjustment to rate base	Adjusted rate base	Equity ROR	AFUDC on equity	Rate base
	(Million dollars)				(Million dollars)	
6.0 pct	85	−77	623	−36.3 pct	−53.2	623
9.0 pct	123	−39	662	−8.2 pct	−14.5	662

12.0 pct	162	0	701	12.0 pct	24.6	701
15.0 pct	200	38	739	27.4 pct	63.0	739
18.0 pct	239	77	778	40.2 pct	101.7	778

NOTE.—Initial adjusted rate base at 12 pct AFUDC equity ROR is composed of $614.1 direct capital costs, $24.6 equity AFUDC, and $62.2 debt AFUDC. The debt capital ratio is 0.75.

D. INCENTIVE RATE OF RETURN SCHEDULE

Though this rulemaking does not propose a specific schedule relating the cost performance ratio to the incentive rate of return on equity, we believe it is useful to discuss the key considerations in choosing a schedule. We solicit comments or suggestions about these or any other factors that are important.

In order to illustrate this discussion, the following table gives four hypothetical schedules. Each schedule gives the average rate or overall rate of return on equity that would be allowed for each level of the cost performance ratio. Also provided is the marginal rate of return, which, is described below.

The Commission believes that four factors are important in choosing the appropriate incentive rate of return schedule:

1. CENTER POINT

The normal rate of return on equity for this pipeline including a premium for any abnormal risks should be allowed if the pipeline is built at "budgeted cost" (the term in the President's "Decision"). The issue then is whether budgeted cost is the final cost estimate to be submitted by the applicant with no expected cost overruns included or whether the Commission should include some cost overruns in the term budgeted cost? The answer to this question may very well depend on how much the final cost estimate submitted by the applicant differs from the March, 1977, estimate. If the final estimate "materially and unreasonably" exceeds the original, the President's "Decision" allows this Commission to not issue a final certificate.

Alternatively, the Commission could use these final cost estimates as the basis for the incentive rate of return schedule, but the normal rate of return would only be allowed if actual costs were equal to or even less than the final cost estimate. In the four hypothetical schedules, the normal rate of return is assumed, for purely illustrative purposes only, to be 12 percent. This rate of return is allowed if the cost performance ratio is 1.3. In other words, the rate of return would only be reduced to below normal if actual costs exceeded budget costs by more than 30 percent, which is approximately the cost overrun expected in the report which accompanies the President's "Decision". The setting of this central point of the schedule will depend on such factors as the relationship between the final cost estimate and the likelihood that the pipeline will experience cost overruns.

Hypothetical incentive rate of return schedules

Performance ratio	Average (marginal) rate of return			
	I	II	III	IV
0.8	19.50 (0)	16.38 (5)	22.63 (−5)	17.63 (5)
0.9	17.33 (0)	15.11 (5)	19.56 (−5)	16.22 (4)
1.0	15.60 (0)	14.10 (5)	17.10 (−5)	15.00 (3)
1.1	14.18 (0)	13.27 (5)	15.09 (−5)	13.91 (2)
1.2	13.00 (0)	12.58 (5)	13.42 (−5)	12.92 (1)
1.3	12.00 (0)	12.00 (5)	12.00 (−5)	12.00 (0)
1.4	11.14 (0)	11.50 (5)	10.79 (−5)	11.14 (−1)
1.5	10.40 (0)	11.07 (5)	9.73 (−5)	10.33 (−3)
1.6	9.75 (0)	10.68 (5)	8.81 (−5)	9.56 (−4)
1.7	9.18 (0)	10.35 (5)	8.00 (−5)	8.82 (−4)
1.8	8.67 (0)	10.06 (5)	7.28 (−5)	8.11 (−5)
1.9	8.21 (0)	9.79 (5)	6.63 (−5)	7.42 (−6)
2.0	7.80 (0)	9.55 (5)	6.05 (−5)	6.75 (−7)

NOTE.—The values in all schedules are based on the formula:

$$r_i=(R_i+R_iA_i+_i-R_iA_i)/(A_i+_iA_i)$$

where r=marginal rate of return
R=average rate of return
A=cost performance ratio
i=step in the schedule

2. Range of Values

The second important issue is the range of values in the schedule. Should the rate of return fall rapidly as costs exceed budgeted costs? Should the rate allowed be substantially higher than normal if the pipeline is built for less than budgeted cost? Should the schedule be symmetrical around the central point? In other words, should the penalty for overruns be different from the reward for underruns? In these four hypothetical schedules, schedule II has the smallest range of values, schedule III the largest.

If the pipeline sponsors are confident that they will not experience significant cost overruns, it would be to their advantage to have a symmetrical schedule with a broad range of values. Thus the incentive rate of return would be substantially larger than normal when the cost performance ratio is low. On the other hand, a narrow range of values may be desired if there is a great deal of uncertainty about project costs.

3. Marginal Rate of Return

The hypothetical schedules give an estimate of the marginal rate of return on equity. This is the rate of return that the sponsors will, in effect, receive on each additional dollar of equity investment needed to finance cost overruns. As an example, suppose that construction costs are such that the cost performance ratio is 1.3 in these schedules. Schedule I provides that existing equity investment will earn a rate of 12 percent, but that an additional dollar will earn a zero rate. Obviously low rates of return are not actually contemplated, but this schedule is equivalent to two rates, an average rate and a marginal rate. As cost overruns occur and since the marginal rate is less than the average, the average will fall.

Schedule I has a constant marginal rate of zero. Schedule II has a constant positive marginal rate of 5 percent. Schedule III has a negative marginal rate of −5 percent, schedule IV has a variable marginal rate ranging from −5 to −7 percent. Schedules with higher marginal rates also have the smaller range in values for the average rate.

The marginal rate is a key factor in choosing a schedule since it is this rate that determines the incentive to control cost overruns. A higher marginal rate provides less incentive than a near-zero or negative rate. A marginal rate near the opportunity cost of equity capital for the pipeline sponsors will create almost no incentive to control cost overruns since the sponsors will be receiving a near normal rate of return on the equity invested to finance the overrun. In addition, if the investment tax credit is considered, the actual marginal rate could be substantially higher than shown here. In schedule IV, the marginal rate declines, and thus the incentive to control overruns increases as the performance ratio increases.

4. Consumer Share of Cost Overruns

Without the incentive rate of return mechanism, consumers would normally pay for any increases in construction costs as these costs would be included in the rate base if found to be prudently incurred. However, in this case, cost overruns also lower the rate of return on equity, which results in effect, in a sharing by equity investors in the cost overruns. Calculating the share of cost overruns incurred by consumers and by equity investors requires a number of assumptions about the capitalization of the pipeline and maturities of the debt component of the invested capital, and has not been attempted here. However, this fact will be considered by the Commission in choosing the schedule.

The final issue concerning the incentive rate of return schedule is when should the Commission establish the schedule? On the one hand, it should be set as soon as possible in order that sponsors of the pipeline will know the conditions under which they are expected to build the pipeline. On the other hand, the Commission can not finally choose a schedule until the final cost estimates are available.

E. WRITTEN COMMENT PROCEDURES

The Commission invites interested persons to submit written data, views and other information concerning the matters set forth in this notice. An original and 14

copies should be filed with the Secretary of the Commission by May 31, 1978. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM78-12.

All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

The Commission intends that persons participating in this proceeding should serve their comments on other participants, and have an opportunity to reply to initial comments in response to this notice. Thus, in order that parties serve their initial comments on other parties and have the opportunity to reply to initial comments, any person intending to file initial comments shall notify the Secretary in writing on or before May 19, 1978, of his or her intention to participate. A service list will be prepared and mailed to those who have stated an intention to participate. Initial comments shall be filed with the Secretary as stated above, and in addition, each party shall serve initial comments on parties on the service list by May 31, 1978. Parties may file reply comments with the Secretary in accordance with the procedures set forth above, and shall serve them upon parties on the service list by June 9, 1978.

In consideration of the foregoing, it is proposed that the following terms and conditions be attached to the conditional certificates of public convenience and necessity issued by the Commission on December 16, 1977 ("Alcan Pipeline Co., et al.", Docket Nos. CP78-123, CP78-124, and CP78-125), as set forth below.

By direction of the Commission.

KENNETH F. PLUMB,
Secretary.

TERMS AND CONDITIONS

DEFINITIONS

For purposes of the following terms and conditions, the Alaska Natural Gas Transportation System within the United States as specified in the President's "Decision and Report to Congress on the Alaska Natural Gas Transportation System" (the "Decision"), transmitted to Congress on September 22, 1977, and approved by both Houses on November 2, 1977, will be divided into three pipelines: (1) the portion of the system within the State of Alaska, (2) the portion of the system from the United States/Canada border near Monchy, Saskatchewan, to a point near Dwight, Ill., and (3) the portion of the system from the United States/Canada border near Kingsgate, British Columbia, to the State of California. In the following terms and conditions the term pipeline refers to each of the three pipelines, and the terms and conditions apply to each. The schedules, parameters, or variables to be established by the Commission in order to implement the following terms and conditions may be different for each of the three pipelines that compose the Alaska natural gas transportation system. The term system will refer to the entire Alaska natural gas transportation system in the United States.

TERMS AND CONDITIONS

(1) *Cost Performance Ratio.* Pursuant to the second finance term and condition of the President's "Decision," the rate of return on equity allowed during the operating period of the pipeline will be increased if the pipeline is completed under budgeted cost and lowered if the pipeline is completed over budgeted cost. The basis for determining the allowed rate of return will be a cost performance ratio. This is the ratio of the conventional or normal rate base or gross plant in service. The conventional rate base is defined in Condition 2, and the projected rate base is defined below in Condition 3. The Commission will determine at a later date a schedule or formula that will specify the allowed rate of return for each value of the cost performance ratio.

(2) *Conventional Rate Base.* The conventional rate base will be determined by established principles and will be based on actually experienced capital or construction costs found by the Commission to be prudently incurred with an allowance for funds used during construction (AFUDC). The AFUDC will be based on the amount of debt and equity outstanding during construction, the actual interest rates paid on the debt, and a normal or conventional rate of return on equity to be established by the Commission pursuant to Condition 8.

(3) *Projected Rate Base.* The projected rate base will be based on the final cost estimate submitted to and approved by the Commission pursuant to Condition 4 after adjustment for inflation pursuant to Condition 6 and for changes in scope pursuant to Condition 7. The amount of AFUDC included in the projected rate base will be based on the actual interest rates experienced during construction, on the amounts of debt and equity that would have been outstanding if the expenditures for construction as projected in the final cost estimate after adjustment for inflation and changes in scope have actually occurred, and on the normal return to equity to be specified by the Commission.

(4) *Final Cost Estimate.* Pursuant to the second finance condition in the President's "Decision," the applicant shall submit to the Commission a final direct capital cost estimate in 1975 constant dollars adjusted to reflect any design changes that result from the Agreement on Principles with Canada and any Addendum thereto. This final cost estimate must also be submitted in a format and with costs set forth in categories to be specified by the Commission (see Condition 5). The March, 1977, cost estimate referred to in the second finance term and condition in the "Decision" (p. 36), must also be resubmitted in the same format for comparability with the final cost estimate. An explanation for any significant differences between cost components in the March, 1977, and in the final cost estimate must be provided. The Commission reserves the right to withhold certification if the final cost estimate materially and unreasonably exceeds the cost estimate submitted by the applicant in March, 1977.

(5) *Cost Estimate Format.* In order to assure comparability between cost estimates submitted by the applicant and to measure the impact of changes in scope, all cost estimates must be submitted in a format or according to specifications to be determined by the Commission. Prior to submittal of the final design cost estimate, the applicant may submit a proposed format for these estimates. The format proposal should specify the cost components of the estimate broken down by pipeline segment, pipeline facility, timing of expenditure, and cost category. The breakdown of costs in the format shall be in sufficient detail that the Commission may compare the various cost estimates and determine the reasonableness of any changes.

(6) *Adjustment for Inflation.* For each major cost category or component of the final cost estimate, the Commission will specify a price or cost index that will be used to measure the increase in costs due to general inflation in the economy. Each cost or price index will be an existing index that is widely used to measure the increase in prices or costs for that category of commodities or services. The Commission will give first preference to indexes published by the U.S. Government, but indexes calculated by private institutions may also be used if they are widely used and generally accepted. The applicant may submit to the Commission proposed price or cost indexes along with his proposed cost estimate format referred to in Condition 5. The price or cost indexes specified by the Commission will be used to convert the constant dollar estimates in the final cost estimate into current dollar estimates prior to calculating the projected rate base.

(7) *Changes in Scope.* Prior to calculating the projected rate base for purposes of determining the cost performance ratio, the final cost estimate will be adjusted to reflect increases and decreases in cost that result from a limited number of changes in scope of the project. For the changes in scope that occur, the applicant shall submit a revised final cost estimate showing how the changes in scope would have altered the cost estimate if the changes in scope and the time of their occurrence were known prior to submitting the final cost estimate. The revised cost estimate will reflect the fact that the changes in scope occurred during the construction period and thus may result in a larger cost change than if they occurred prior to the start of construction. The revised final cost estimate must be submitted in the format specified by the Commission pursuant to Condition 5, and all changes in the final cost estimate must be explained and justified. Except for changes in cost assumptions resulting from the changes in scope, all other assumptions in the cost estimate such as assumptions about labor productivity or prices of labor and materials shall remain unchanged. The changes in scope for

which changes in the final cost estimate shall be made are limited to the following:

1. Changes in volumes and location of gas inputs to the system, in volumes and location of gas offtakes from the system, compression or horsepower requirements, and refrigeration requirements;

2. Changes in pipeline size or operating pressure;

3. Delay in date of startup or initial operation of the system due to delays in completion of the pipeline segments in Canada or delays in delivery of gas by the gas producers or sellers;

4. Changes in design or location of pipeline segments and related facilities in order to be compatible with facilities or pipeline segments in Canada;

5. Changes in design or location of the pipeline and related facilities that meet three conditions: they (a) are necessary to meet environmental protection requirements by the Federal or State governments, (b) could not reasonably have been anticipated by the applicant prior to submission of final cost estimate, and (c) would not otherwise be necessary to protect the integrity of the pipeline, public health and safety, or neighboring facilities and structures;

6. Changes in Federal and State laws and regulations that occur after the submission of the final cost estimates and require changes in the design or routing of the system or significantly affect costs of construction for the system.

(8) *Normal Rate of Return.* Prior to final certification, the Commission shall specify a normal rate of return on equity for this pipeline that is within the general range for rates of return for other pipelines allowed by the Commission. This rate of return on equity will be determined separately and independently from the incentive rate of return. This rate of return will reflect, or compensate equity investors for, any unusual risks associated with this pipeline. Throughout the construction or operation of the pipeline pursuant to Section 5 of the Natural Gas Act, the Commission may alter this rate of return to reflect changes in rates of return allowed on other pipelines, the need to attract capital for expansion of the system, or to provide just and reasonable compensation to equity investors including consideration of any abnormal risks that may be associated with this pipeline that are not common to other pipelines.

(9) *Cost of Service Calculation.* Instead of calculating the cost of service of the pipeline over the operating life based on what may possible be an abnormally high or low rate of return on equity equal to the incentive rate, the cost of service will be based on a normal return on equity established pursuant to Condition 3 and on an adjusted rate base. The adjustment to the rate base is designed so that from the point of view of the equity investors the adjusted rate base and the normal rate of return will offer a stream of income over the life of the project that is equivalent in present value terms to the unadjusted rate base and the incentive rate of return.

(10) *Adjustment to Rate Base.* For purposes of calculating the allowed cost of service, the rate base and the equity capital account at the time of commissioning the pipeline will be adjusted either up or down by an amount to be calculated in three steps. First, the return of equity and the after-tax return on equity over the life of the system will be estimated based on the unadjusted rate base determined pursuant to Condition 2 above, on an after-tax rate of return on equity capital equal to the incentive rate, and on a financing and capitalization plan approved by the Commission. Second, the present worth or present value of this time stream of return to and on the equity will be calculated using a discount rate equal to the normal rate of return on equity established pursuant to Condition 3. Third, the equity capital account set at the time of commissioning will be equal to this present value total. The rate base will be assumed to be increased or decreased by the same amount as the equity capital account is increased or decreased.

—Footnote—

[1] "Commissioning," in this context, is a term used herein to describe that point in the Commission's procedures where a final certificate has been issued, construction is complete, and service has commenced. See 18 CFR 157.20(c)(3).

¶ 31,992 Elimination of Certain Rate-Change Filings

43 F.R. 26026 (June 16, 1978).

[18 CFR Parts 2, 154, 260]

[Docket No. RM78-14]

ELIMINATION OF CERTAIN RATE-CHANGE FILING REQUIREMENTS

Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: By this rulemaking, the Commission proposes to amend its rules to eliminate: Rate change filing requirements for periodic escalations and changes in tax now required under the applicable national or area rate opinions; and to initiate: Review of actual rates collected on an annual basis through modification of Schedule 0505 of Form 108. The purpose of the rulemaking proposals is to eliminate numerous compliance-type rate change filings.

DATE: Comments due on or before July 10, 1978.

ADDRESS: Send comments to Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Elisabeth Pendley, Office of the General Counsel, 202-275-4216.

JUNE 9, 1978.

Pursuant to 5 U.S.C. 553, sections 4, 5, 7, 14, 15 and 16 of the Natural Gas Act (52 Stat. 822, 823, 824, 828, 829, 830; 15 U.S.C. 717c, 717d, 717f, 717m, 717n, 717o), and pursuant to Section 403(a) of the DOE Act (91 Stat. 565), the Commission gives notice that it proposes to amend:

General Rules under Natural Gas Act, Subchapter A, Chapter I, Title 18, CFR; Regulations under Natural Gas Act, Subchapter E, Chapter I, Title 18, CFR; Approved Forms, Natural Gas Act, Subchapter G, Chapter I, Title 18, CFR.

The Commission[1] proposes to provide an alternative procedure which would result in the elimination of certain rate change filing requirements made by producers in compliance with the national[2] or applicable area[3] rate opinions permitting periodic base rate escalations on specific dates or changes in tax.

In order to provide the information necessary for its regulatory responsibilities, the Commission also proposes to amend the annual report form filed by producers.[4]

Specifically, the Commission proposes to amend § 2.5a(j) of General Policy and Interpretations and § 154.94 of Rate Schedule and Tariffs by providing an option to the following rate change filing requirements:

(1) The one cent quarterly increase rate filing requirement for sales from wells commenced on or after January 1, 1975;[5]

(2) The one cent annual increase rate filing requirement for sales from wells commenced on or after January 1, 1973 and prior to January 1, 1975;

(3) The one cent annual increase rate filing requirement for sales from wells commenced prior to January 1, 1973, and dedicated on or after January 1, 1973 to the interstate market for the first time, or for rate renewal (rollover) contracts,[6] or for the rate for new reservoirs discovered on or after January 1, 1973 as a result of a well completion or recompletion commenced prior to January 1, 1973, or for completion operations into a different formerly non-productive reservior commenced on or after January 1, 1973, in a well commenced prior to January 1, 1973;

(4) Changes in tax permitted under the various national or area rate opinions where the producer is collecting the applicable national or area ceiling rate, including those sales being made at the minimum base rate of 18.0¢ as prescribed in Opinion No. 749-C.

These compliance-type rate filings reflect an escalation "in rate, charge, classification or service" which has already been adjudicated as just and reasonable.[7] The amendments to the regulations governing these escalations offer an alternative approach which should eliminate a substantial number of unnecessary filings.[8]

This proposal does not suggest an alternative to the filing requirements for the producer's right to charge the applicable ceiling for a particular vintage of the gas, such as those caused by newly commenced wells[9] or recompletions on or after January 1, 1973, in a previously nonproductive formation encountered in a previously drilled well.[10] However, comments on the question of whether or not procedures similar to those proposed here could be made applicable to changes in rate for sales of a different gas vintage are solicited.

The proposed amendment would permit a producer, once it has established its right to collect the applicable national or area ceiling rate for a particular sale, or for a portion thereof to make a single filing in affidavit form indicating its intention to automatically collect any contractually authorized periodic escalation in base rate or change in tax prescribed by the applicable national or area rate opinion. A producer may include future sales once they are certificated at the applicable ceiling rate, or where it has subsequently established its right to collect the applicable ceiling rate for its existing sales or portions thereof. An affidavit would specify that by this election the producer consents to comply with any subsequent Commission order directing refunds with applicable interest if rates are collected in excess of the just and reasonable rate.

The proposed language for the affidavit is as follows:

ATTESTATION PURSUANT TO §§ 2.56a(j)(4) AND 154.94(c)(1) OF THE REGULATIONS UNDER THE NATURAL GAS ACT

The following must be attested to by a Senior officer[10a] _____ (Senior officer of filing party) certifies that he is_____(exact legal title of attester) of _____ (filing party) and that the filing party:

(1) Has heretofore filed changes in rate schedules pursuant to Sections 154.94 and 2.56a(j) of the Regulations under the Natural Gas Act, which establishes its right to collect the national or area rate prescribed in the applicable national or area rate opinion, for the sales and gas vintages as listed in the attached Exhibit A to this affidavit.

(2) Has complied with all the requirements of law in filing such changes.

(3) Hereby elects to collect the periodic escalations and changes in tax for the sales and gas vintages listed in Exhibit A as contractually authorized and as prescribed in the applicable national or area rate opinion when they become effective without filing further changes pursuant to § 154.94 and § 2.56a(j),

(4) Specifically recognizes and agrees that the revenues so collected will be refunded without delay and with applicable interest pursuant to Section 4 of the Natural Gas Act in the event the revenues collected are found to be higher than the applicable just and reasonable rate for the sale involved.

(5) Hereby agrees it will file further affidavits as necessary to include subsequent sales or gas vintages for which it qualifies.

The undersigned has made a diligent inquiry of persons with personal knowledge of the facts contained in the filing party's filings pursuant to § 154.94 and § 2.56a(j) after such inquiry, has determined that all statements made in such filings are true and accurate, concerning, among other things, the factors relating to the eligibility to charge the rates therein.

_____

(Signed)

EXHIBIT A

Producers Name	Rate Schedule No.	Buyer	Applicable Vintage Rate Previously Established	Effective Date of Rate Establishment

This proposal does not relieve any producer of the responsibility, where applicable, to file a statement of eligibility with respect to certain new wells and recompletions under Section 2.56a(p) (Opinion No. 770-A, mimeo p. 196). Nor does the proposal have any applicability to situations where a producer is not entitled contractually to collect the applicable national ceiling rate under Opinion No. 770, as amended, or where a producer has not established its right to collect such rate for sales under a particular rate schedule. The proposal does not apply to rate change filings necessitated by the negotiation of rate renewal (rollover) contracts. Nor does it include unilateral rate increases under expired contracts when there is no replacement contract or contract increases at levels below or up to the applicable ceiling rate or changes in additive or deductive charges. Further the proposal does not eliminate the rate change filing requirements for other sales not specifically covered by the national or area rates.[11]

Concurrently with this proposal to eliminate certain producer rate change filings, the Commission proposes to monitor the rates charged by all producers having active rate schedules on file with this Commission through modification of Schedule 0505 of Form 108. Specifically, the Commission proposes to alter the filing requirements of § 260.6 by enlarging Schedule 0505 to require a year's history of the actual rates collected, and related actual sales volume. The required reports would contain sufficient detail to permit verification of the various rate components.[12] The producer would continue to file all contracts and amendments thereto affecting sales, allowing the staff to check the applicable ceiling rate for the various time periods involved against the contractual pricing provisions.

Any interested person may submit to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, to be received no later than July 10, 1978, data, views, comments or suggestions in writing concerning all or part of the amendments proposed herein. Written submittals will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours. The Commission will consider all such written submittals before acting on the matters herein proposed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Submittals to the Commission should indicate the name, title, mailing address, and telephone number of the person to whom communications concerning the proposal should be addressed.

Comments on all aspects of the proposals are solicited. As noted above the Commission specifically requests comments on the question of the applicability of procedures similar to those proposed herein to changes in gas vintage.

The proposed amendments to the Commission's Rules and Regulations under the Natural Gas Act would be issued under the authority granted the Federal

Energy Regulatory Commission by the Natural Gas Act, particularly Sections 4 and 16 (52 Stat. 822, 830; 15 U.S.C. § § 717c, 717o), and pursuant to Section 403(a) of the DOE Act (91 Stat. 565).

PART 2—GENERAL POLICY AND INTERPRETATIONS

(A) The following is a proposed amendment to Part 2—General Policy and Interpretations, in Subchapter A—General Rules, Chapter I, Title 18 of the Code of Federal Regulations:

Add a new § 2.56a(j)(4) which reads as follows:

§ 2.56a Area price levels for natural gas sales by independent producers.

* * * * *

(j)* * *

(4) Any person who has established the right to collect the Opinion No. 770-A rate for "new gas" sales under its particular rate schedule, may elect to make a single filing in affidavit form which will permit collection of all future quarterly escalations and changes in tax. The rates are to be collected subject to refund liabilities with applicable interest, in the event they are found to have been collected in excess of the applicable just and reasonable rate.

PART 154—RATE SCHEDULES AND TARIFFS

(B) The following are proposed amendments to Part 154—Rate Schedules and Tariffs, in Subsection E—Regulations under the Natural Gas Act, Chapter I, Title 18 of the Code of Federal Regulations:

Amend § 154.94(b) by adding the phrase ". . . Once the single filing is made in affidavit form in compliance with § 154.94(c)(1), the above conditions for timely filing do not apply" and add a new paragraph (c)(1), as follows:

§ 154.94 Changes in rate schedules.

(b) Every change in any rate schedule, rate, charge, classification or service effective or applicable to a sale subject to the jurisdiction of the Commission as of June 7, 1954, and on file with the Commission, or required to be filed pursuant to § 154.92, or in any rate schedule, rate, charge, classification or service effective or applicable to a sale subject to the jurisdiction of the Commission initiated subsequent to June 7, 1954, on file with the Commission, or required to be filed with the Commission pursuant to § 154.92 shall be filed with the Commission in triplicate not less than 30 days nor more than 90 days prior to the date such change in rate schedule is proposed to be made effective. Once the single filing is made in affidavit form in compliance with § 154.94(c)(1), the above conditions for timely filing do not apply.

(c)* * *

(1) Any producer who has established its right to collect the Opinion No. 770-A rates for sales (i) from wells commenced on or after January 1, 1975, or (ii) from wells commenced on or after January 1, 1973 and prior to January 1, 1975, or, (iii) from wells commenced prior to January 1, 1973 and dedicated on or after January 1, 1973 to the interstate market for the first time, or (iv) under renewal (rollover) contracts, or from new reservoirs discovered on or after January 1, 1973 as a result of a well completion or recompletion commenced prior to January 1, 1973, or (v) from completion operations into a different formerly nonproductive reservoir commenced on or after January 1, 1973 in a well commenced prior to January 1, 1973; or (vi) from changes in tax under the national or area rate opinions where the producer is collecting the applicable national or area ceiling rate, including those sales being made at the minimum base rate or 18.0¢ as prescribed in Opinion No. 749-C may elect to make a single filing in affidavit form which will cover such prescribed periodic escalation and tax change provisions. Said rates are collected subject to refund liabilities, with applicable interest in the event they are found to have been collected in excess of the applicable rate.

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

(C) The following is a proposed amendment to Part 260—Statements and Reports (Schedules) Subchapter G—Approved Forms, Natural Gas Act, Chapter I, Title 18 of Code of Federal Regulations:

Amend § 260.6(b) by adding the phrase "* * * except to the extent modified in Sections 154.94(c)(1) and 2.56a(j)(4)," as follows:

§ 260.6 Rate schedule analysis on a continuing current basis.

* * * * *

(b) Each person found by the Commission to be a natural gas company as defined by the Natural Gas Act, as amended, 52 Stat. 821, that is required to submit a rate schedule to the Commission pursuant to § 154.92 of the Regulations shall prepare and file with the Commission an original and 3 copies of the rate schedule analysis report, FPC Form No. 108, or the applicable schedules thereof, each and every time a rate schedule is either submitted to the Commission for the first time or a rate schedule presently on file with the Commission is proposed to be amended, except to the extent modified in Sections 154.94(c)(1) and 2.56a(j)(4).

(D) The following are the proposed additions to be made to Schedule 0505, Form 108:

—

Note: the proposed additions to Schedule 0505, Form 108 are not reproduced.

—

INSTRUCTIONS FOR COMPLETING SCHEDULE NO. 505

I. DESCRIPTION

This schedule is designed to collect data on annual sales volumes and revenues sold under each rate schedule including annual volumes and revenues attributed to those parties whose sales are covered by the rate schedule involved, in addition to the respondent.

This schedule is also to be used by respondents to submit the detailed information necessary to track rate increases or tax increases authorized or permitted by either the escalation provisions of national rate opinions or applicable area rate opinions.

II. GENERAL INFORMATION

A. The co-owner ("et al.") interests in annual volumes sold and revenues received to be reported on Schedule 505 are those co-owner interests that would be covered by the respondent's rate schedule under Section 154.91(b) of the Commission's Regulations in the absence of small producer regulation and are the volumes and revenues of co-owners that are (a) large producers, large producer affiliates or pipeline affiliates or (b) small producers that have not acquired Small Producer Certificates.

B. It is responsibility of the reporting producer to determine the status of each of the co-owners of gas sold under each rate schedule. If the co-owner interest is not covered by either another rate schedule or by a Small Producer Certificate, the reporting producer is to report the appropriate volumes and revenues of each such co-owner on Schedule 505 in addition to his own. All co-owner parties whose sales are reported on a Schedule 505 are to be identified. (See instructions for Data Field No. 6, Part II, for instances where the sales volume cannot be broken down by individual parties.)

C. This schedule shall be submitted by all producers of natural gas maintaining one or more rate schedules on file with the Commission. In instances where there have been no sales under a rate schedule during the report year enter a zero in Data Field No. 19 and state the reason in the Remarks Section.

D. Respondents shall complete all applicable data fields on this schedule annually.

E. A separate schedule shall be submitted for each separate rate schedule multiple analysis on file with the Commission as of the end of the reporting period. (If the multiple analysis code is unknown, assign a single digit numeric code for use until appropriate coding is available.)

Multiple analysis shall not be required solely on the basis of varying Btu content. In these cases, an average Btu content should be reflected.

F. A separate schedule shall be submitted for each suspension docket. If there are more "other" (co-owner) parties covered by the rate schedule than can be entered on one schedule, enter the information described as Key on another Schedule 505, increment the page number and continue naming parties on an additional Schedule 505. Report only volumes and revenues subject to refund as of the end of the reporting year.

G. Data corrections shall be submitted using this same schedule and specifying the original Key data values and the corrected data values.

H. All volumes and rates shall be reported at 14.73 PSIA at 60 Fahrenheit.

I. Prior to use of this schedule to track rate increases resulting from a periodic

change in the applicable national or area base ceiling rates or from adjustments to these base ceiling rates caused by tax increases, it is necessary that the respondent has previously filed the affidavit required by Section 154.94(e)(1) of the Commission's Regulations.

J. Sales volume and revenue data shall be reported on a gross basis for the purpose of this schedule, and consist of the respondent interest, the interest of others on whose behalf the respondent files, and the royalty interest related thereto.

III. DETAILED INSTRUCTIONS

The following individual data field instructions are cross-referenced to the corresponding schedule layout by data field number. All references to rate schedules apply to rate schedule multiple analysis.

Data Field Number and Instructions

Part I—Rates charged

1.—*Filing Date* (N6): for FERC Use Only. (TMDATE)

2.(Key).—*FERC rate schedule number.* (A4): Enter the rate schedule number assigned by the FERC. (IDRATE)

3. (Key).—*Multiple analysis code* (A1): Enter the appropriate multiple analysis code for the rate schedule being reported. The same multiple analysis codes shall be used by respondents in making corrections or subsequent filings. (IDDESC)

4.—*Regulation section* (A15): Enter the applicable section and subsection of the Rules and Regulations as set forth in the Code of Federal Regulations and/or as set forth in the ordering paragraphs of the FERC Opinion pursuant to which the change in rate was made. (IDDESC)

5.—*Contract basis for rate increase* (A26): Enter the specific contract provision pursuant to which this rate change was made—contract, article, paragraph, etc. If the rate change was authorized by a Commission opinion, state the opinion number. (IDDESC)

6. (Key).—*Buyer code* (N6): Enter the code assigned to the individual buyer of gas, from the publication entitled Buyer/Seller Codes, *IDBYSL*. If the buyer name is not in the publication, leave this field blank.

7.—*Buyer name* (A35): Enter the name of the buyer of gas as it appears in the publication entitled Buyer/Seller Codes, *IDBYSL*.

8. (Key).—*State Abbreviation, County Code* (A5): Enter the combined State/County code which represents the state and county of the producing acreage covered by the contract from the publication entitled Geographic Codes, *IDNGAR*. If the producing acreage is located in more than one state or county, list the other(s) in the Remarks Section.

9.—*Field/Plant Code* (A6): Enter the code for the primary gas producing field or plant from the publication entitled Field/Plant Codes, *IDGFLD, IDGPLT*.

10.—*Field/Plant Name* (A26): Enter the name of the primary gas producing field or plant, from the publication entitled Field/Plant Codes *IDGFLD, IDGPLT*. Enter other field or plant name(s) in the Remarks Section.

11.—*Effective Date* (N6): Enter the date when the rate change became effective. The first line of this data field and Data Field Nos. 12 through 16 should always reflect the rate in effect on January 1. (TMDATE)

12.—*Base Rate* (N3.4) CTS/Mcf: Enter the base rate, exclusive of tax reimbursement and all other additive or deductive charges for the period on and after the effective date in Data Field No. 11.

13.—*Tax Reimbursement* (N3.4) CTS/Mcf: Enter the amount of seller's tax obligation that the buyer reimbursed to the seller on and after the effective date in Data Field No. 11.

NOTE.—Data Field No. 14 (Btu Adjustment) and Data field No. 15 (Other Charges) can have negative values; to indicate a negative value, code a negative sign (−) in the right most position of Data Field No. 14 and the right most position of the ¢/Mcf section of Data Field No. 15. Deductions in Data Field No. 15 should be indicated by coding a negative sign closed in parenthesis following the applicable code; i.e., a buyer deduction for compression should be coded as C(−).

14.—*Btu Adjustment* (N3.4) CTS/Mcf: Enter the Btu adjustment on and after the effective date in Data Field No. 11.

15.—*Other Charges* (N3.4) CTS/Mcf: Enter the net amount resulting from the summation of all other additive or deduc-

tive charges, excluding tax reimbursement and Btu adjustment, on and after the effective date in Data Field No. 11. Enter the code designation of such charges under the code heading and enter the details of such charges in the Remarks Section. These codes are as follows:

D—Dehydration

G—Gathering

C—Compression

T—Treating

O—Other (explain in the Remarks Section)

16.—*Total Rate* (N3.4) CTS/Mcf: Enter the total amount charged on and after the effective date in Data Field No. 11. (Summation of Data Fields 12, 13, 14, and 15.)

17.—*Sales Volume* (N12) Mcf: Enter the actual sales volume for the period following the effective date in Data Field No. 11, in Mcf.

18.—*Revenue* (N9) DOL: Enter the actual revenue for the sales volume in Data Field No. 17.

19.—*Total Sales Volume* (N12) Mcf: Enter the total sales volume sold under the rate schedule for the reporting period, including co-owner sales not reported under separate filings, in Mcf. This volume should be the total of all volume in Data Field No. 17.

20.—*Total Sales Revenues* (N9) DOL: Enter the total sales revenue received under the rate schedule for the volume entered in Data Field No. 19 above, rounded to the nearest dollar. This revenue should be the total of all revenue in Data Field No. 18.

21.—*Owner/Operator Indicator* (A1): Enter one of the following codes to indicate if you are the operator: (INYONO)

Code/Description:

Y = Yes

S = Yes, in some units

N = No

22.—*Estimated Total Sales Volume* (N12) Mcf: Enter the estimated total sales volume to be sold under the rate schedule for the following report period, in Mcf.

23.—*Sales Volume Subject to Refund* (N12) Mcf: Enter the total sales volume sold under the rate schedule subject to refund for each suspension docket under the rate schedule, in Mcf.

24.—*Sales Revenues Subject to Refund* (N9) DOL: Enter the total sales revenue for the volume reported in Data Field No. 23 above, that was sold subject to refund under the suspension docket entered in Data Field No. 25 below.

25 (Key).—*Suspension Docket Number* (A9): Enter the FERC suspension docket number under which the volume and revenue entered in Data Field Nos. 23 and 24 above were sold. (IDDCKT)

NOTE.—If the rate schedule is involved in more than one suspension proceeding (more than one "RI" docket), one Schedule 505 is required for each docket, and Data Field Nos. 19, 20, and 22 should be identical for each Schedule 505.

26.—*Remarks* (A84): Enter any explanatory or qualifying remarks that may be necessary. (IDDESC)

Part II—Co-owner data

1.—*Filing Date* (N6): For FERC Use Only. (TMDATE)

2 (Key).—*FERC Rate Schedule Number* (A4): Enter the rate schedule number assigned by the FERC. (IDRATE)

3 (Key).—*Multiple Analysis Code* (A1): Enter the appropriate multiple analysis code for the rate schedule. The same multiple analysis codes shall be used by respondents in making corrections or subsequent filings. (IDDESC)

NOTE.—Report co-owner sales not reported under a separate filing. If more co-owners are to be reported than can be placed on one page, enter the information described as Key on another Schedule 505, increment the page number, and continue naming co-owners.

4 (Key).—*Co-owner Code* (N6): Enter the code number assigned to the individual co-owner, from the publication entitled Buyer/Seller Codes, *IDBYSL*. If not available, leave blank and complete Data Field No. 5 below.

5 (Key).—*Co-owner Name* (A35): Enter the name of the co-owner. If a composite report as indicated by Data Field No. 6, enter "COMPOSITE REPORT" and list the co-owner names. (IDETAL)

6.—*Number of Co-owners* (N3) NO: Use this data field when sales volume cannot be broken down for individual parties. Enter the number of parties associated with the volume entered in Data Field No. 7 below on the first line of this data field. Leave blank if this is not a composite report.

7.—*Co-owner Volume* (N11) Mcf: Enter the sales volume for each co-owner listed in Data Field No. 5 above, or for the number of parties entered in Data Field No. 6, above, in Mcf.

8.—*Co-owner Revenue* (N9) DOL: Enter the sales revenue for each co-owner listed in Data Field No. 5 above, or for the number of parties entered in Data Field No. 6 above.

9.—*Co-owner Sales Volume Subject to Refund* (N12) Mcf: Enter the volume interest of each co-owner, or of the number of parties indicated in Data Field No. 6 above, that was sold subject to refund under the suspension docket entered in Data Field No. 25 of Part I above, in Mcf.

10.—*Co-owner Revenue Subject to Refund* (N9) DOL: Enter the revenue interest of each co-owner, or of the number of parties indicated in Data Field No. 6 above, that was sold subject to refund under the suspension docket entered in Data Field No. 25 of Part I above.

NOTE.—Volumes and revenues under rate schedules covering limited term, optional pricing and special relief type sales should be reported on Schedule 505. These sales should be identified in the Remarks Section. Emergency sales should not be included in Schedule 505.

Small producers who maintain rate schedules on file should complete Schedule 505 to report annual sales and revenues under each of those rate schedules.

(E) The Secretary shall cause prompt publication of this notice to be made in the FEDERAL REGISTER.

By direction of the Commission.

KENNETH F. PLUMB,

Secretary.

—Footnotes—

[1] Prior to October 1, 1977, "The Commission" refers to the Federal Power Commission; subsequent thereto it refers to the Federal Energy Regulatory Commission.

[2] Opinion No. 770-A, "National Rates For Jurisdictional Sales Of Natural Gas Dedicated To Interstate Commerce On Or After January 1, 1978, For The Period January 1, 1975 To December 31, 1976," 56 FPC_____, Opinion issued Nov. 5, 1976, aff'd sub nom. Opinion No. 770-A also incorporated Opinion No. 699-H, "Just and Reasonable National Rates For Sale Of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973," 52 FPC 1604, Opinion issued December 4, 1974. Opinion No. 749-C, "Just And Reasonable National Rates For Sales Of Natural Gas From Wells Commenced Prior to January 1, 1973, 56 FPC_____, Opinion issued July 19, 1976 in Docket No. R-478.

[3] For example, Opinion No. 662 prescribed area rates in the Permian Basin Area for sales under contracts dated on or after October 1, 1966, and prior to January 1, 1973 in excess of the otherwise applicable national rate of Opinion No. 749-C for such flowing gas. Opinion No. 662, "Area Rate Proceeding (Permian Basin Area II)," 50 FPC 932, Opinion issued August 7, 1973 in Docket No. AR70-1.

[4] Schedule 0505 of Form 108, Independent Producer Annual Rate Schedule Sales Data.

[5] Previously, producers were permitted under Opinion No. 770-A to make a single filing covering the just and reasonable rate as of July 27, 1976, together with the 1.0¢ per Mcf periodic escalations due to become effective through July 1, 1977. However, presently the producers are required to file for each increase separately. Order No. 556-A, "Rate Schedule Analysis On A Continuing Current Basis," FPC Form 108, "Order Granting In Part And Denying In Part Rehearing And Reconsideration," issued August 5, 1977, in Docket No. RM76-10.

[6] In a rate renewal (rollover) contract the sale is made pursuant to a replacement contract where the sale was formerly made pursuant to a permanent certificate of unlimited duration under such prior contract which expired of its own term on or after January 1, 1973, or pursuant to a contract executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

[7] 18 CFR § 154.94(c), implementing Section 4(d) of the Natural Gas Act provides: The operation of any provision of the rate schedule providing for future or periodic changes in the rate, charge, classification, or service after June 7, 1954, or the operation of any like provision in any rate schedule filed after June 7, 1954, shall constitute a change in rate schedule.

[8] It is estimated that approximately 11,000 compliance-type rate filings annually could be eliminated by this proposed alternative.

[9] Presently, a producer is required to file a rate increase from the rate established under the rate schedule to the $1.42 base rate (now $1.49) established in Opinion No. 770, as amended.

[10] Presently, a producer is required to file a rate increase up to the 52.0¢ (now 54¢) base ceiling rate applicable to this sale.

[10a] Senior officer means, as applicable, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer, General Partner (or senior officer thereof) or Sole Proprietor.

[11] For example, special relief cases, limited term certificates, and in those situations where a natural gas company does not produce the gas but receives compensation from the purchaser at a rate in excess of that authorized for producers for gathering and compression services.

[12] Presently this is accomplished through the detailed data reported several times during the year in rate change filings, including estimates of Btu content and sales volumes, on Schedule 0507 of Form 108 which will now be eliminated in regard to the filings included hereunder.

¶ 31,993 Review of Settlement Agreements

43 F.R. 32814 (July 28, 1978).

[18 CFR Parts 1, 2]

[Docket No. RM78-16]

REVIEW OF SETTLEMENT AGREEMENTS

Proposed Rule

JULY 24, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: This rule amends the Federal Energy Regulatory Commission's (Commission) regulations to facilitate Commission review of settlement agreements. It provides that, once a hearing has been ordered, settlement agreements will be received by the Commission only upon certification by the presiding administrative law judge, who is to determine whether the settlement is in the public interest or, if contested, whether the contested issues can be decided on their merits on the basis of substantial evidence.

DATE: Comments must be received on or before August 31, 1978.

ADDRESSES: Send comments to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Written submissions will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during regular business hours.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, 202-275-4166.

SUPPLEMENTARY INFORMATION:

A. BACKGROUND

It has been the policy of the Federal Power Commission and the Federal Energy Regulatory Commission[1] to accept for filing, both directly and by way of certification by a presiding administrative law judge, settlement agreements containing wholly and partially settled matters, 18 CFR 1.18. The submittal and consideration of settlement agreements permits expeditious resolution of cases where those settlements are found to be in the general interest of the public. Consideration of settlements to which the parties have not unanimously agreed but which are supported by substantial evidence on the record and meet the standards enunciated in the Federal Power Act or Natural Gas Act also permits a more expeditious resolution of an ongoing proceeding. *Mobil Oil Corporation* v. *F.P.C.*, 417 U.S. 283 (1973).

Nevertheless, the need for more fully developed records, or records on which a reasoned decision can be made, has become apparent in recent cases in which offers of settlement with certain contested issues were submitted to the Commission before the parties had the opportunity, or having been presented the opportunity chose not to exercise it, to submit testimony or to cross-examine those witnesses who submitted testimony.[2]

In an effort to alleviate this problem, and, more importantly, to expedite the issuance of final decisions and to provide the assurance that participants are afforded due process of law in presenting and litigating their views before this Commission, the Commission is hereby proposing new procedures for certifying settlement agreements to the Commission once a hearing has been ordered. Before that time, the parties may submit an offer of settlement to the Commission. The Commission invites interested persons to comment on this proposed rulemaking.

B. SUMMARY OF THE COMMISSION'S PROPOSED REGULATIONS

The proposed procedures are intended to assure that offers of settlement certified to the Commission are either unanimously supported or, if contested by any participants to the proceedings, that the presiding administrative law judge has determined that all parties have had an opportunity to present evidence or have waived their right to do so, as to issues which they contest. The Commission may thereby render a decision on contested issues on the basis of substantial record evidence, consistent with the requirements of due process.

In cases where a hearing has been ordered by the Commission, the Commission proposes to review offers of settlement only upon certification of the offer of settlement and all pertinent documents, testimony, and exhibits by the

presiding administrative law judge. If the offer of settlement is contested, the judge shall certify the offer of settlement together with his finding that the contested issues are severable and either his decision on the merits of contested issues, or, if a waiver of the initial decision is requested, his determination that the record contains substantial evidence to enable the Commission to reach a decision on the merits of contested issues. The participants shall outline the scope of the offer of settlement, including applicable contracts, schedules, or documents filed with the Commission in current and, if applicable, prior proceedings.

Comments. The Commission currently receives comments from the parties upon the filing of an offer of settlement with the Commission. The Commission proposes that, where a hearing has been ordered by the Commission, the settlement shall be filed with the presiding officer. The Secretary shall thereupon issue a notice of the offer of settlement and provide for the filing of initial comments (and reply comments, if deemed appropriate by the presiding officer) with the presiding officer. The purpose of filing comments with the presiding officer is to allow him to determine prior to certification whether an offer of settlement is unanimously supported and ripe for Commission review as a settlement, or, if portions of it are contested, to determine if the participants wish to present furtner evidence on the record, and to render a decision on the contested portions of the offer of settlement in the absence of a request for waiver of the initial decision.

Contested issues. If there are contested issues, the presiding officer shall provide the participants an opportunity to present evidence or to cross-examine opposing witnesses. He may defer certification until he concludes the hearing and renders a decision on the contested issues, or he may certify the uncontested portion of the agreement to the Commission, or, as a third alternative, if waiver of his decision is requested, he may certify the record together with his determination that the record contains substantial evidence from which the Commission may reach a reasoned decision on the contested issues and that the disposition of the contested issues will not affect the settled issues.

The Commission will, by the proposed rule, no longer accept offers of settlement certified by the presiding officer which are accompanied by contested issues, unless the parties have either exhausted or waived their rights to further proceedings before the presiding officer, including the introduction of evidence in support of their positions, and the presiding officer has either determined that substantial evidence has been presented to support the settlement offer or rendered an initial decision on the merits of the severable contested issues. Briefs on exceptions and briefs opposing exceptions would be submitted to the Commission upon an initial decision.

The participants may request a waiver of the requirement for an initial decision on the contested portions of the offer of settlement. (See 18 CFR 1.30(c).) In that event, the presiding officer shall certify to the Commission the motion for waiver of his initial decision, the entire offer of settlement, with pertinent documents and supporting portions of the record, and the comments of the participants, upon his determination that the disposition of the contested issues will not affect the settlement, that the record contains substantial evidence from which the Commission may reach a reasoned determination on the merits of the contested issues, and that the participants have either exhausted or waived their rights to present additional evidence in the proceeding before the presiding officer. The participants will be bound by the Commission's ultimate decision on the merits of the contested issues. This does not preclude any party from seeking rehearing of the Commission's order on the contested issues, nor does anything in the rule preclude any party from requesting a hearing in the event that the Commission rejects or substantially alters the terms of the settlement agreement by accepting it subject to conditions.

In consideration of the foregoing, it is proposed to amend Part I, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

Any interested person may submit to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, to be received no later than August 31, 1978, views, comments, and suggestions in writing

concerning all or part of the amendments proposed herein. Written submittals will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours. The Commission will consider all such written submittals before acting on the matters herein proposed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Submittals to the Commission should indicate the name, title, mailing address, and telephone number of the person to whom communications concerning the proposal should be addressed.

Comments on all aspects of the proposal are solicited.

Issued in Washington, D.C., on July 24, 1978.

By order of the Commission.

KENNETH F. PLUMB,
Secretary.

1. Code of Federal Regulations, chapter I of title 18, part 1, subchapter A, § 1.1(f), is amended by adding new subparagraph (23) reading as follows:

§ 1.1 The Commission.

* * * * *

(f) *Definitions.* * * *

(23) *Offer of settlement.* For the purpose of this paragraph and §§ 1.18, 1.36, and 1.4(d)(2)(v), an offer of settlement shall include all documents, testimony, and exhibits, which provide support for the offer of settlement, a list of all schedules, contracts, documents, or data within the scope of the settlement, and a proposed notice suitable for publication in the FEDERAL REGISTER.

2. Code of Federal Regulations, chapter I of title 18, part 1, Subchapter A, § 1.18(e), is revised to read as follows:

§ 1.18 Conferences; offers of settlement.

* * * * *

(e) *Procedures for submission of offers of settlement to Commission.*—(1) *General rule.* Any participant to a proceeding may submit an offer of settlement, as defined by § 1.1(f)(23), to all participants and to the presiding officer, and may request a conference for such purpose. If the Commission has ordered a hearing at the time the offer of settlement is submitted, the offer of settlement shall be filed with the presiding officer. The participant submitting the offer of settlement shall state whether the settlement is a package, with no severable parts, or whether any specific issues may be separated from the settlement for separate decision, should the need for a separate decision arise. An unaccepted offer of settlement shall be privileged and shall not be admissible in evidence against any person claiming such privilege.

(2) *Comments.* The presiding officer shall fix the time and order for filing comments with him, and may permit the filing of reply comments. These procedures shall be set forth in a notice to be published in the FEDERAL REGISTER by the Commission Secretary.

(3) *Unopposed offer of settlement.* If the offer of settlement is unopposed, the presiding officer shall certify to the Commission the offer of settlement, his statement that the offer of settlement is unopposed, and the evidentiary record, which shall include support for the offer of settlement.

(4) *Contested offers of settlement.* If the offer of settlement is opposed in whole or in part, the presiding officer shall either: (i) Defer his certification of the offer of settlement until he has reached a decision supported by substantial record evidence on the remaining contested issues; or (ii) upon a determination that the disposition of the remaining contested issue or issues will not affect the settlement, certify to the Commission the uncontested portion of the offer of settlement, as provided in subparagraph (3) of this paragraph, specifying issues which are contested and are severable from the offer of settlement, and proceed with hearing procedures on the remaining contested issue or issues; (iii) in lieu of the procedures set forth in § 1.30(c), the participants may file with the presiding officer a motion for waiver of an initial decision on the contested portions of the offer of settlement, with the request that he certify the motion to the Commission. The presiding officer shall only certify to the Commission the motion, the entire offer of settlement, including the contested portions, the record, and the comments of the parties if he determines that: (a)

The disposition of the contested issues will not affect the uncontested portions of the settlement, *(b)* the record contains substantial evidence from which the Commission may reach a reasoned decision on the merits of the contested issues, and *(c)* all participants either have had or have waived the opportunity to present evidence and/or cross-examine opposing witnesses. If these three conditions are not met, the presiding officer shall establish such further procedures as he deems appropriate.

(5) *Reservation of rights.* Any participant may reserve its right to a hearing if the Commission does not accept and approve the unopposed portion of the offer of settlement, or approves it subject to conditions which substantially alter the result of the offer of settlement or the underlying intent of the participants.

3. Code of Federal Regulations, Chapter I of Title 18, Part 1, Subchapter A, § 1.30(c)(1) and § 1.30(c)(3) are amended to read as follows:

§ 1.30 Decisions.

* * * * *

(c) *Waiver and omission of intermediate decision procedure.* (1) In lieu of any intermediate decision (initiated by presiding officer, recommended by presiding officer or designated responsible officer, or tentative by the Commission), any party or staff counsel in any proceeding may request that the Commission forthwith render the final decision. Except as provided in § 1.18(e)(4)(iii), if all other parties and staff counsel join or concur in such request, it shall be deemed to have been granted unless the Commission denies such request within 10 days next following its submission or filing. Except as provided in § 1.18(e)(4)(iii), such requests for omitting the intermediate decision procedure shall specify:

(i) The concurrence of the other parties and staff counsel;

(ii) Whether opportunity for presenting oral argument of filing briefs before the presiding officer or Commission is desired or waived;

(iii) Whether opportunity for presenting proposed findings and conclusions with supporting reasons therefor, is desired or waived; and

(iv) Whether the parties reserve only their rights to apply to the Commission for rehearing and to petition for judicial review of the Commission's decision or order as may be provided for by the statute under which the proceeding was initiated and conducted.

* * * * *

(3) Except as provided in § 1.18(e)(4)(iii), requests for waiver and omission of the intermediate decision procedure shall be by motion filed with the Commission at any time during, but not later than five days next following, the conclusion or adjournment sine die of the hearing; shall be in writing under oath, subscribed and verified; and shall in all other respects conform to the requirements of § § 1.12 and 1.15 to 1.17, inclusive: *Provided, however,* That during sessions of hearings in proceedings, motions for such waiver and omission may be made orally on the record before the presiding officer, who shall forthwith report the same to the Commission.

§ 2.1 [Amended]

4. Code of Federal Regulations, Chapter I of Title 18, CFR Part 2, § 2.1(a)(1)(i)(H) is deleted.

—Footnotes—

[1] The "Commission" when used in the context of an action taken prior to October 1, 1977, refers to the FPC; when used otherwise, the reference is to the FERC.

[2] See, for example, *North Penn Gas Co.*, docket No. RP76-158, order granting rehearing, establishing procedures, and granting motion to vacate order, issued on Nov. 30, 1977. After the Commission completed its analysis of the record before it and issued a decision based on the evidence presented, a certain party requested a hearing on the contested issues, thereby withdrawing unilaterally from the agreements. The Commission therefore was required to remand the proceeding to the presiding administrative law judge.

¶ 31,994 Natural Gas from Certificate Requirements

43 F.R. 36471 (August 17, 1978).

[18 CFR Parts 2 and 157]

[Docket No. RM78-7]

NATURAL GAS FROM CERTIFICATE REQUIREMENTS

Proposed Exemptions for Temporary Sale, Delivery, or Transportation Arrangements

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes that §§2.68, 157.22 and 157.29 of Title 18, Code of Federal Regulations be revoked and replaced by new §§157.45 through 157.52. Review of the existing emergency purchase exemptions indicates the present provisions should be modified. The proposed regulations consolidate and modify the existing regulations and define the circumstances under which exempted emergency natural gas supplies can be bought, sold, and transported in interstate commerce.

DATES: Comments must be received on or before September 13, 1978.

ADDRESS: Interested persons may participate in this proposed rulemaking by submitting written data, views or arguments to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Teresa Ponder, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4284.

SUPPLEMENTARY INFORMATION:

Background

The Commission is reevaluating and proposing to revise the emergency purchase provisions of its regulations taking cognizance of the narrow construction given the exemption provision of section 7 of the Natural Gas Act (15 U.S.C. 717f) under which the present 60-day programs were instituted (in *Consumers Federation of America* v. *F.P.C.*, 515 F.2d 347 (D.C. Cir. 1975), and the frequent use of the emergency provisions. On April 7, 1978, the Commission requested discussion and comments from the public regarding the following subjects: The criteria to be used in determining the existence of an emergency; the types of consumers to whom emergency supplies should be made available; the proper relationship of emergency supplies in regard to system supply; the need for price guidelines and what they should be; the proper method of recovering the costs of emergency supplies; the effects of emergency purchases on the price of intrastate supplies and on the ability of the interstate market to attract new onshore reserves; the proper role of limited-term certificates in alleviating emergencies; and the legal limitations on certification exemptions. The comments submitted, as summarized below, expressed divergent opinions on each point.

Summary of the Comments

Many of the comments questioned the necessity of changing the emergency provisions since natural gas which would otherwise be unavailable to the interstate market could be acquired for critical needs during supply shortages if the present regulatory scheme is maintained.

Criteria for Determining an Emergency

While no consensus was reached, many of the comments indicated that the existence of an emergency should be determined by focusing on the actual needs at the end-use level rather than at the level of pipeline curtailment, except in the case of severe curtailments and force majeure situations. On the other hand, as many comments indicated, such a focus might impede the current effectiveness of the emergency programs. Comments also expressed concern that end-use requirements might cause administrative problems since end-use criteria would be hard to evaluate at the time of an emergency and not provide sufficient flexibility for the pipelines.

Qualified Purchasers

Although most of the comments agreed that emergency gas should be limited to high priority users, many expressed the opinion that the suggested limitations were too restrictive and that certain additional industrial users should be allowed

to obtain emergency gas. The class of excluded users which expressed the most concern were consumers with alternate fuel facilities, because occasionally, alternate fuels are not available when there is a natural gas emergency. These consumers stated that unless they are allowed to purchase emergency supplies when alternate fuels are unavailable, the emergency regulations might provide a disincentive to install alternate fuel facilities.

Most comments emphasized a critical need for allowing pipelines to store emergency supplies. It was argued that although excessive emergency purchases should be avoided, pipelines and distributors should not be discouraged from attempting to forecast and obtain the necessary supplies for winter requirements by disallowing the recovery of the costs incurred in the purchase of excess emergency supplies.

The Proper Role of Pipelines and Distributors

Comments suggested that pipelines should usually act as a broker or agent, purchasing emergency gas for particular purchasers. Pipelines should purchase emergency gas for system supply only to meet a force majeure situation or a severe curtailment, or to fill summer storage. In all other situations, the gas should be specifically assigned to the designated purchaser. Many of the comments, however, indicated that specific assignment of emergency natural gas might present an impossible administrative task for pipelines and distributors. Several comments suggested that the distributors and direct industrial consumers should be able to contract for and store their own emergency supplies.

Price Guidelines

Many commentators opposed the promulgation of price guidelines because emergency situations may require extraordinary measures, including high prices, to guarantee the gas will be immediately available. It was suggested that should price guidelines be established, they would be workable only if they (1) provide some assurance that pipelines will be able to recover the cost of emergency supplies, (2) are flexible, creating a zone of reasonableness, and (3) allow market forces to operate. With regard to the price of the gas, the comments emphasized the need to allow recovery of all costs. The guideline most often suggested was a zone approximating the prevailing intrastate prices.

Transportation guidelines were suggested which allowed recovery of all costs of gathering and transporting the gas. Generally, it was assumed that the price of transporting emergency gas would be no higher than the cost of transporting nonemergency gas supplies, but that any exceptional expenses should be recovered. The prevalent concern was that restrictive price guidelines would deter emergency sales.

Method of Recovering Costs

The comments were divided as to whether or not the costs of emergency supplies should be rolled-in with other costs of purchased gas and recovered through the PGA accounts. Most interstate pipelines argued that the costs should be flowed through the PGA accounts because, when emergency supplies flow, benefit accrues to all customers on the line, and it would be discriminatory to require certain customers to bear the entire burden of the cost of the emergency gas. Comments which argued against rolling in the costs through the PGA accounts cited the fact that permitting rolled-in costs disguises the high price of emergency supplies, encourages increased use of emergency gas and forces high priority users, who do not usually have to resort to emergency gas, to subsidize its use by lower priority users.

Market Effects of Emergency Purchases

Most parties who addressed the subject of market effects stated that emergency gas purchases would have a minimal effect on intrastate gas prices or on availability of new gas supplies to the interstate market. Some commentators believed that many reserves dedicated to the intrastate market are simply not available to the interstate market. Producers suggested that emergency gas programs, in fact, encourage dedications to the interstate market because they allow the producer to tap wells immediately while applications for certification are pending.

Limited-Term Certifications

Most comments indicated that the Commission should encourage the limited-term procedure. It is generally be-

lieved by commentators, however, that a limited-term certificate program cannot take the place of emergency gas purchases and should only be used to augment emergency supplies.

Several comments supported the requirement that limited-term certificates be granted only for gas otherwise unavailable to the interstate market, but added that such a requirement should not be interpreted to mean that the producers must have an intrastate contract in hand. In the past, such an interpretation has discouraged the seeking of limited-term certificates because by the time the seller has an intrastate contract, he does not need to sell the gas in the interstate market.

Limited-term certification raises the issue of whether or not gatherers and intrastate pipelines should be given these certificates, and if so, whether their uncertified suppliers should also be required to seek certification. It was generally agreed in the comments that the extension of the Commission's jurisdiction over the producers of these supplies would reduce the available supplies because producers as a rule might seek to avoid Federal jurisdiction to the point of refusing to make sales that would subject them to jurisdiction.

LEGAL BOUNDARIES OF EMERGENCY EXEMPTIONS

Most parties feel that the present program meets the legal requirements established by the Natural Gas Act and the courts.

Most parties who addressed the issue stated that for the purposes of emergency purchases, the Commission can legally continue to regulate nonjurisdictional producers' rates indirectly: *Provided*, That rates meet the standards of section 4 of the Natural Gas Act. Most comments suggested that in "Consumer's Federation of America v. F.P.C.", 515 F.2d 347 (D.C. Cir. 1975), the Court of Appeals criticized the Commission's method of indirect regulation, but did not rule that indirect regulation was invalid *per se*. Rather, it required that more specific guidelines be established by the Commission in this regard.

MISCELLANEOUS

There is substantial disagreement over whether or not take-or-pay provisions should be allowed. Some comments argued that take-or-pay provisions drive up the price of emergency gas, while others believe that the price of gas would significantly increase if take-or-pay provisions were barred.

DETERMINATION OF THE COMMISSION

The Commission has determined that, except in the case of a pipeline emergency, it is appropriate to define emergency by focusing on the needs of ultimate end-users, not on a pipeline's level of curtailment. Experience developed over the years, with respect to ultimate end-use effects of a pipeline's level of curtailment at the wholesale level, demonstrate that little or no correlation exists between curtailment and the needs of ultimate end-users. Because pipeline curtailment is not an adequate indication of an emergency situation, imminent or reasonably anticipated curtailments of end-user supplies will be proposed as the criteria for determining the existence of an emergency.

Section 1(b) of the Natural Gas Act extends the authority of the Commission:

* * * to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but * * * not * * * to any other transportation or sale of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

Because the emergency transactions which the Commission is proposing to exempt would otherwise require a certificate of public convenience and necessity, the Commission may specify the conditions and circumstances under which a given emergency transaction will be exempt. These conditions and circumstances may properly be related to the activities of buyers, sellers, or transporters under the emergency transactions, in a manner consistent with the Commission's jurisdiction.

Broad authority in a similar situation has been exercised by the Commission in the FPC Order No. 533 program which was recently reviewed and continued with

modifications by FERC Order No. 2. FPC Order No. 533 was recently affirmed by the District of Columbia Circuit Court of Appeals.[1] The Commission may also base a pipeline's curtailment plan upon end-use principles.[2]

The Commission's jurisdiction does not extend to the services performed by a local distribution company or to the methods of accounting for emergency supplies or to the recovery of the costs of emergency supplies by a distributor. The Commission may, however, determine that a distribution company qualifies to enter into emergency transactions only when certain customers are threatened with curtailment under that distribution company's curtailment plan. It is also permissible for the Commission to specify that pipelines, under most circumstances, should directly assign their gas purchases, and related costs, to their customers which require emergency supplies.

The proposed rule incorporates these and similar concepts for several reasons. Allowing pipelines to obtain emergency natural gas for system supply, except in special circumstances, may encourage purchases of emergency supplies in excess of actual emergency needs. When the cost of emergency supplies is included with the cost of pipeline system supplies, the burden of paying for this gas is spread among all the pipeline's customers even though only certain customers may require or benefit from these emergency supplies. On the other hand, if a pipeline's direct sale and distribution company customers are directly assigned the costs of the gas, responses to emergency situations will be properly circumscribed and the beneficiaries of these transactions will pay the full cost thereof.

The existence of a natural gas emergency usually requires immediate purchase and delivery of emergency supplies. The purchaser must compete for intrastate gas otherwise unavailable to the interstate market, and the purchaser usually pays intrastate rates to obtain it. Since there must be an extraordinary need for the gas, the Commission has determined that as long as the emergency transaction complies with this proposed rule, it will be deemed to be in the public interest.

With respect to the Commission's evaluation of the proposed rule and comment thereon, the Commission intends to make use of the data filed in current pipeline curtailment omnibus proceedings. Such use is appropriate and permissible in this informal rulemaking proceeding, in light of the intended purpose of the omnibus proceedings to gather data and information for the benefit of the Commission.

It is the Commission's intent that these regulations be self-executing. They will permit interstate pipelines and their customers to promptly react to emergency situations as they develop without seeking prior Commission approval of emergency transactions conducted in accordance with this subpart.

SUMMARY OF THE AMENDMENTS

The Federal Energy Regulatory Commission (Commission) proposes that §§ 2.68, 157.22, and 157.29 be revoked and replaced by §§ 157.45 through 157.52. Section 2.68 authorizes distribution companies not under Commission jurisdiction, as well as intrastate pipelines, to make sales and deliveries of natural gas in interstate commerce to distribution companies and interstate pipelines in need of temporary emergency gas supplies for 60 days. Section 157.22 authorizes the construction and operation of facilities and the sale of natural gas without a certificate where the sale is necessary to assure maintenance of adequate natural gas service. Section 157.29 authorizes independent producers, under certain conditions, to sell and transport natural gas to interstate pipelines for a 60-day period without a certificate. Under all three sections, an emergency exists when the pipeline is forced to curtail its services. Also, a pipeline has the option of treating the emergency natural gas as system supply and recovering its costs through purchased gas adjustment (PGA) accounts.

As proposed, the new regulation would eliminate these three exemptions and replace them with a single regulation.

OUTLINE OF MAJOR FEATURES OF PROPOSED 60-DAY EMERGENCY REGULATION

Section 157.45—Purpose. The construction and operation of facilities or the sale or transportation of emergency gas would be exempted from certificate requirements of the Natural Gas Act under certain conditions. It would be the policy

of the Commission to monitor emergency natural gas transactions. The Commission proposes to accord a rebuttable presumption of prudence to transactions conducted in accordance with this subpart.

Section 157.46—Definitions. A pipeline emergency would be defined as a sudden unanticipated loss of supply or a situation where immediate action is required for protection of life, health, or property. The term "pipeline emergency" would be adopted rather than "force majeure." "Emergency" would mean a pipeline emergency or a situation where actual curtailment of natural gas service is imminent or reasonably anticipated to occur to any of the following end-users:

(1) Any residential consumer;

(2) Any commercial or industrial consumer whose average daily requirements are less than 300 Mcf per day;

(3) Any industrial consumers for feedstock, process, or plant protection uses; and

(4) Any commercial or industrial consumer other than an electric utility:

(i) Whose requirements exceed 300 Mcf per day;

(ii) Which does not have installed alternate fuel facilities or which does not have alternate fuel immediately available;

(iii) Whose operations would be substantially impaired without additional gas supplies.

If imminent or reasonably anticipated curtailment of an end-user electric utility presents a danger to life, health, or maintenance of physical property, the electric utility would qualify for relief from its pipeline supplier under the terms of § 154.46(a). However, when the curtailment would not result in such a danger to life, health, or maintenance of physical property, the electric utility would be required to receive prior Commission approval before participating in the emergency program.

"Qualified sellers" would include producers, intrastate pipelines, interstate pipelines, and distribution companies. "Qualified purchasers" would include distribution companies and interstate pipelines.

Section 157.47—Exemptions from certificate requirements. Qualified sellers and transporters of emergency natural gas are exempted from the certificate requirements of the Natural Gas Act, when the emergency transactions are conducted in accordance with the provisions of this subpart.

Section 157.48—Terms and conditions of emergency purchases—General conditions. The proposed § 157.48 would permit distribution companies and interstate pipelines to purchase emergency natural gas, but require them to make every reasonable attempt to conduct their operations in such manner as to minimize or avoid reliance upon emergency supplies. Flexibility would be accorded purchasers to account for colder-than-normal winter weather while forecasting natural gas supplies and needs for the winter.

Distribution companies and direct sale customers would be required to verify to the pipeline that an emergency exists.

The proposal provides that the Commission could take appropriate action to insure compliance with the conditions of this subpart. Among other remedies available to the Commission, it could, after notice and opportunity for hearing, declare any person found to have engaged in emergency transactions in violation of this subpart to be ineligible to participate in further emergency transactions without prior Commission approval. Producers who use this subpart to circumvent the certificate requirements of section 7 of the Natural Gas Act, among other remedies, could be declared ineligible.

Duration. Emergency transactions would continue to be limited to a period of not more than 60 consecutive calendar days, except where the Commission determines that there is a natural gas emergency which is national or regional in scope, or for an additional period of not more than 60 days, where a seller, other than a producer, has requested a waiver and the Commission has not issued an order denying the waiver for the additional 60 days. A producer could not continue to sell emergency natural gas from a well beyond the initial 60-day period unless the producer had filed an application for a permanent or temporary certificate and sold the gas, after the initial 60-day period, at the applicable national or area rate ceiling.

System supply and direct assignment of supplies. The proposal provides that in-

terstate pipelines could purchase emergency natural gas for general system supply only when a pipeline emergency exists or for summer storage injection. Interstate pipelines could purchase emergency natural gas and directly assign volumes and costs associated with such gas, including transportation costs, to its direct sale customers and resale distribution companies faced with an emergency, if requested by the customers. Interstate pipelines could also act as agent or broker in acquiring and transporting emergency natural gas for distribution companies. In the event this regulation is adopted, pipelines which engage in emergency transactions will be expected to file tariff changes, if necessary, so that the cost of emergency supplies may be allocated to specific pipeline customers.

Emergency purchases for summer storage injections. Emergency natural gas supplies could be purchased for summer storage injection when the scheduled injections could not be made from nonemergency natural gas supplies without creating an emergency during the injection period.

Section 157.49—Price ceilings for emergency transactions—Transportation prices. Generally, interstate pipelines would determine a transportation charge based upon the transmission costs included in the pipeline's effective sales rates. The revenues received for the transportation and other services would be credited to the deferred account and flowed back to the pipeline's customers except for a small nominal charge of 2 cents per Mcf which may be retained by the pipeline. The 2 cents per Mcf allowance is not intended to apply to any other jurisdictional transaction.

Natural gas prices. Except for production from the Federal offshore domain, sales of emergency natural gas by producers could be made at a rate no higher than the national or area rate ceiling plus allowable adjustment, or at a rate not in excess of the rate for current intrastate producer's sales of comparable location and contract vintage as reported in FPC form 45, to create a rebuttable presumption of prudence. In addition, the purchaser must seek and obtain that supply of gas which results in the lowest total cost by inquiring of at least three qualified sellers as to the cost and availability of gas from such sellers.

Sales of emergency natural gas by intrastate pipelines and distributors should be made at the lesser of (1) the weighted average systemwide cost of gas supplies plus a normal charge for gathering and transportation to the point of delivery or (2) the lowest offer obtained after inquiring of at least three qualified sellers. A rebuttable presumption of prudence will also attach to a sale made at a cost in excess of the weighted average systemwide cost of gas if the requisite three inquiries are made and if the seller can show that it will actually incur the claimed higher cost of gas in acquiring and delivering the emergency supplies.

The proposal provides that compliance with the price guidelines would create a rebuttable presumption of prudence. Failure to comply with the guidelines would place on the purchaser the burden of demonstrating prudence. If the lowest price offered by qualified producers did not fall within the published FPC form 45 data, the rebuttable presumption of prudence would not be created. The presumption of prudence would be rebutted upon a showing that the purchaser's efforts to comply with these requirements did not actually constitute a good faith effort to obtain the emergency supplies at the lowest available cost.

Section 157.50—Reporting requirements for emergency transactions. The proposed regulations require that within 48 hours after commencement of deliveries, the interstate pipeline should report by telegram to the Commission the nature of the emergency and other relevant aspects of the emergency transaction. Interstate pipelines which transport emergency supplies would file reports with the Commission every calendar quarter.

Section 157.51—Waiver of requirements for emergency transactions. The Commission would be able to waive the requirements of this subpart.

Section 157.52—Drilling or testing and purging new natural gas pipeline facilities. This proposed section provides that gas service for the drilling of new oil or gas wells, or for testing and purging of a new natural gas pipeline facility, would

be exempted from certificate requirements.

PUBLIC COMMENT PROCEDURES

Interested persons may participate in this proposed rulemaking by submitting written data, views, or arguments to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before September 13, 1978. Each person submitting a comment should include his name and address, identify the notice (Docket RM78-7), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

(Natural Gas Act, as amended (15 U.S.C. 717), Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, it is proposed to amend Parts 2 and 157, Chapter I of Title 18, the Code of Federal Regulations, as set forth below.

By direction of the Commission.

LOIS D. CASHELL,
Acting Secretary.

§ 2.68 [Deleted]

1. Part 2 is amended by deleting § 2.68 in its entirety.

§§ 157.22 and 157.29 [Deleted]

2. Part 157 is amended by deleting §§ 157.22 and 157.29 in their entirety and by adding new subparts C (§§ 157.45 through 157.51) and D (§ 157.52), to read as follows:

Subpart C—Exemption of Emergency Sale, Delivery, or Transportation Arrangements for Natural Gas From Certificate Requirements.

Sec.

157.45 Purpose.

157.46 Definitions.

157.47 Exemptions from certificate requirements.

157.48 Terms and conditions of emergency transactions.

157.49 Price ceilings for emergency transactions.

157.50 Reporting requirements for emergency transactions.

157.51 Waiver of requirements for emergency transactions.

AUTHORITY: Natural Gas Act, as amended (15 U.S.C. 717), Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.

Subpart C—Exemption of Emergency Sale, Delivery, or Transportation Arrangements for Natural Gas From Certificate Requirements.

§ 157.45 Purpose.

(a) The purpose of this subpart is to prescribe the conditions under which certain emergency transactions involving the construction and operation of facilities or the sale, transportation and delivery of natural gas in interstate commerce are exempt from the requirements of section 7 of the Natural Gas Act.

(b) It shall be the policy of the Commission to monitor emergency natural gas transactions to the extent necessary to assure compliance with the requirements of this subpart.

(c) It shall be the policy of the Commission to accord a rebuttable presumption of prudence to emergency natural gas transactions conducted in accordance with this subpart, and, unless such presumption is successfully rebutted in subsequent rate proceeding, to permit companies subject to the jurisdiction of the Commission to recover those costs incurred in accordance with this subpart.

§ 157.46 Definitions.

For purposes of this subpart:

(a) "Pipeline emergency" means (1) a sudden unanticipated loss of gas supply or (2) a situation where the pipeline purchaser, in good faith, determines that immediate action is required or is reasonably anticipated to be required for protection of life or health or for maintenance of physical property.

(b) "Emergency" means a pipeline emergency or a situation where actual

curtailment of natural gas service is imminent or reasonably anticipated to occur to any of the following end-users:

(1) Any residential consumer;

(2) Any commercial or industrial consumer whose average daily requirements in a peak month are less than 300 Mcf per day;

(3) Any industrial consumer for feedstock, process, or plant protection use; or

(4) Any commercial or industrial consumer other than an electric utility:

(i) Whose average daily requirements in a peak month exceed 300 Mcf per day.

(ii) Which does not have alternate fuel facilities or which does not have alternate fuels immediately available, and,

(iii) Whose operations would be substantially impaired without emergency natural gas supplies.

(c) "Qualified seller" means any producer, intrastate pipeline, interstate pipeline, or distribution company.

(d) "Qualified purchaser" means a distribution company or interstate pipeline.

(e) "Interstate pipeline" means any natural gas company as defined in section 2(6) of the Natural Gas Act which is engaged in the transportation by pipeline of natural gas.

(f) "Distribution company" means any person (or governmental entity) which receives natural gas for local distribution and resale to natural gas users.

(g) "Intrastate pipeline" means any person (other than an interstate pipeline) engaged in the transportation by pipeline of natural gas.

(h) "Emergency natural gas" means natural gas transported or sold to alleviate an emergency in accordance with this subpart.

§ 157.47 Exemptions from certificate requirements.

(a) Any qualified seller or other person engaged in the transportation or sale of emergency natural gas, or in the construction and operation of facilities for the sale or transportation of emergency natural gas, is exempt from the requirements of section 7 of the Natural Gas Act, to the extent that (1) such sale or transportation of emergency natural gas or such construction or operation of facilities is necessary to alleviate an emergency and (2) such sale, transportation, construction or operation is conducted in accordance with the provisions of this subpart.

(b) Participation in any transaction described in paragraph (a) of this section shall not subject any person to the jurisdiction of the Commission under the Natural Gas Act except to the extent provided in this subpart.

§ 157.48 Terms and conditions of emergency purchases.

(a) *General conditions.* (1) Qualified purchasers may purchase emergency natural gas in accordance with the provisions of this subpart but should make every reasonable attempt to conduct their operations in such a manner as to minimize or, if possible, to avoid continuing reliance upon emergency natural gas supplies.

(2) In applying the definition of emergency, flexibility will be accorded interstate pipelines and distribution companies to account for colder than normal winter weather and to accomodate operations under effective curtailment plans. A reasonable relationship should, exist between volumes purchased under this subpart and the volumes which are anticipated to be needed during the emergency.

(3) When a distribution company purchases, or a direct sale customer or distribution company requests assignment of emergency natural gas, a responsible official of such distribution company or direct sale customer shall advise the interstate pipeline which will make the deliveries, before commencement of the deliveries, that the emergency exists or is imminent and shall provide such pipeline with such information as may be required within sufficient time to enable the pipeline to make the reports required in § 157.50.

(4) After notice and opportunity for a hearing, the Commission may take appropriate action to insure compliance with this subpart. Upon a determination by the Commission that a person has engaged in emergency transactions and has failed to comply with the conditions of this subpart, the Commission may, in addition to any other remedies, declare such person ineligible to engage in further

emergency natural gas transactions without prior Commission approval.

(b) *Duration.*

Emergency transactions under this subpart shall be limited to a period of not more than 60 consecutive calendar days, except in the following cases:

(1) In the event that the Commission determines that there is a natural gas emergency which is national or regional in scope, emergency transactions may continue for such period as the Commission may by order prescribe.

(2) Except for sales by producers, emergency transactions under this subpart may be continued for an additional period of not more than 60 consecutive days where (i) 15 days prior to the end of the initial 60-day period, the qualified purchaser files a petition requesting a waiver so as to permit one additional 60-day period of exemption, describing fully the continued emergency situation, and (ii) the Commission does not, within the 15-day period, by order, prohibit continuation of the emergency transactions for such additional period.

(3) A producer may not continue to sell emergency natural gas from a well beyond the initial 60-day period unless the producer has filed an application for a permanent or temporary certificate to continue such sales within 45 days after commencement of the emergency natural gas deliveries under this subpart. Any deliveries made after the initial 60-day period shall be made at or below the applicable national or area rate ceiling, and may continue at such rates until the Commission acts on the application for the certificate.

(4) No cost associated with facilities instailed by interstate pipelines in connection with emergency transactions shall be included in the pipeline's jurisdictional rates unless a certificate of public convenience and necessity has been issued authorizing such facilities.

(c) *System supply and direct assignment of supplies.* (1) Interstate pipelines may purchase emergency natural gas for general system supply for a pipeline emergency, or for summer storage injection, pursuant to paragraph (d) of this section.

(2)(i) Interstate pipelines may purchase emergency natural gas and directly assign volumes and costs associated with such gas, including transportation costs, to its direct sale and distribution company customers faced with an emergency, if the customer or company complies with paragraph (a)(3) of this section.

(ii) An interstate pipeline, at its discretion, may choose to establish a separate account to cover the cost of all assigned emergency purchases and allocate costs in that account to the individual assignment customers on a weighted average cost basis. If an interstate pipeline purchases emergency gas supplies for direct assignment in quantities greater than related emergency requirements, then the balance may be used for general system supply. It is expected that such excess emergency natural gas volumes will be small and that pipelines will make every reasonable attempt to balance assignments with supplies. Interstate pipelines may also act as brokers or agents in acquiring and transporting emergency natural gas for distribution companies faced with an emergency and shall cooperate with these companies in arranging for such acquisition and transportation.

(d) *Emergency purchases for summer storage injections.* (1) Emergency natural gas supplies may be purchased for summer storage injection when:

(i) It is reasonably anticipated that failure to make natural gas injections would result in unfulfilled scheduled storage inventories at the beginning of the winter, and,

(ii) The pipeline, in good faith, determines that projected nonemergency natural gas supplies are not adequate to meet scheduled storage injections without creating an emergency during the injection period.

(2) The quantities of emergency supplies purchased to fill storage shall bear a reasonable relationship to the quantities otherwise needed to meet storage injections and to avoid an emergency during the injection season.

§ 157.49 Price ceilings for emergency transactions.

(a) *Transportation prices.* (1) Interstate pipelines rendering transportation services under this subpart shall determine transportation charges as follows:

(i) In the event a pipeline has on file an effective transportation rate schedule applicable to transactions under this subpart, the pipeline will employ the rate(s) contained therein.

(ii) If an interstate pipeline does not have a transportation rate schedule applicable to transportation services rendered under this subpart, then it shall determine transportation charges applicable to such services as follows:

(A) Such charges shall be based upon the transmission costs then included in the pipeline's effective sales rates.

(B) In calculating such charges, the pipeline shall employ the methodology used in designing rates to recover the transportation component included in its then effective sales tariffs; except where the pipeline has on file an effective transportation schedule applicable to certified transportation service in which case the transportation charge shall be designed consistent with the methodology employed under that rate schedule.

(iii) The revenues received for the transportation and any other services, including all brokerage fees, in excess of 2 cents per Mcf shall be credited to a deferred account and flowed back to the pipeline's customers, except where the pipeline can demonstrate that its out-of-pocket costs actually exceed 2 cents per Mcf or that the level of its effective base tariff rates is predicated upon (A) billing units which include specific volumes of emergency gas purchased or anticipated to be purchased by the pipeline or (B) revenues received for the transportation of emergency gas volumes which were credited to the test-year cost of service. Thus, pipelines shall be required to flow through all revenues from emergency transactions in excess of 2 cents per Mcf which are not reflected in the level of the pipeline's effective base tariff rates. Volumes for compressor station fuel and lost and unaccounted for gas shall be provided by the party for whom the transportation is rendered.

(2) Intrastate pipelines rendering transportation service under this subpart shall determine transportation charges in a manner consistent with both the cost and methodology for calculating transportation charges to the customers of that pipeline.

(b) *Natural gas prices.* (1) Except for production from the offshore Federal domain, sales of emergency natural gas by producers shall be accorded a rebuttable presumption of prudence if made in accordance with subparagraph (4) of this paragraph, and if made at a rate no higher than the applicable national rate plus allowable adjustment, or at a rate not in excess of the rate for intrastate producer sales of comparable location and contract vintage as reported in the most current summary report of FPC Form 45 data publicly available at the time the parties entered into the transaction. In no event shall sales by producers pursuant to this subpart from the offshore Federal domain be made at rates in excess of the applicable national rate.

(2) Sales of emergency natural gas by intrastate pipelines or distribution companies shall be accorded a rebuttable presumption of prudence if made in accordance with subparagraph (4) of this paragraph, and if made at its weighted average systemwide cost of gas supplies plus a charge for gathering and transportation to the point of delivery. The gathering and transportation charge should reflect and be consistent with both the cost and methodology for calculating transportation costs to the customers of the distribution companies or pipeline. A rebuttable presumption of prudence will also be accorded to a sale made in accordance with subparagraph (4) of this paragraph, when the sale is made under a pricing method using a cost of gas in excess of the weighted average systemwide of gas if the seller provides a written statement, under oath, verifying the fact that it will actually incur the claimed higher cost of gas in acquiring or delivering the gas which constitutes the emergency supplies.

(3) Sales by interstate pipelines shall be made at rates prescribed in their tariffs.

(4) Prior to entering into any emergency purchases, the qualified purchaser shall diligently seek and obtain that supply of gas which results in the lowest total cost by inquiring of no fewer than three qualified sellers as to the cost and availability of gas from such sellers.

§ 157.50 Reporting requirements for emergency transactions.

(a) Within 48 hours after commencement of deliveries of emergency natural gas, the interstate pipeline shall notify the Commission by telegram of the sale, stating the specific nature and duration of the emergency (specifically noting whether the purchase is to be added to system supply for a pipeline emergency or for summer storage); the amount of emergency natural gas to be purchased, on a daily basis, the name of the seller, transporter, and any person to whom the emergency natural gas is to be assigned; and the price.

(b) For any period during which an interstate pipeline engages in any transaction for emergency natural gas, the interstate pipeline shall file with the Commission, within 30 days after the end of the calendar quarter, whether the transactions are completed or in progress, a sworn statement and four conformed copies thereof, which shall include the following information:

(1) Identification of each emergency transaction completed or in progress;

(2) The volumes of each emergency natural gas delivered during the quarter under each transaction;

(3) The total moneys received or other compensation received by each seller for each emergency sale during the quarter;

(4) The total amount of moneys received or other compensation received by each transporter for each emergency sale delivered during the quarter;

(5) The charges and the methods by which each transporter's compensation was derived;

(6) Information relied on to determine eligibility for each purchase;

(7) The volumes of emergency natural gas included in system supply for pipeline emergencies, and the volumes of natural gas included in system supply during summer storage; and

(8) A statement from a responsible company official attesting that the activities of the interstate pipeline carried out in accordance with the requirements of this subpart and to the best of its knowledge, an emergency did exist or was reasonably anticipated, and (a) a sworn statement from a responsible company official of each purchasing distribution company or each direct sale customer or distribution company which requested the assignment of emergency supplies describing the emergency circumstances as required by § 157.48(a)(3).

§ 157.51 Waiver of requirements for emergency transactions.

The Commission may by order waive the requirements of this subpart in connection with any emergency transaction to the extent required by the public interest.

Subpart D—Exemption of Natural Gas Service for Drilling, Testing, or Purging From Certificate Requirements

§ 157.52 Drilling of gas or oil wells and testing or purging of new natural gas pipeline facilities.

(a) Construction and operation of facilities necessary to render direct natural gas service for use in the drilling of gas or oil wells or for the use in the testing and purging of new natural gas pipeline facilities are exempted from the certificate requirements of section 7(c) of the Natural Gas Act, when the construction and operation of such facilities are conducted in accordance with paragraph (b) of this section.

(b) Operations undertaken to render direct natural gas service shall be terminated upon the completion of the well or the purging or testing of the pipeline facilities. Persons undertaking any construction or operation of facilities or service under this section shall file an original and two copies of an annual statement, by February 1 of each year, describing their activities hereunder.

—Footnotes—

1 "American Public Gas Association et al. v. FERC," D.C. Cir. No. 75-2105, Decided May 10, 1978.

2 "State of North Carolina v. FERC," D.C. Cir. No. 76-2102. Decided July 13, 1978.

¶ 31,995 Proposed Exemption of Aviation Gasoline and Kerosene-Base Jet Fuel from Mandatory Pricing and Allocation Regulations

43 F.R. 41224 (September 15, 1978).

[10 CFR Parts 210, 211, and 212]

[Docket No. EA78-2]

PROPOSED EXEMPTION OF AVIATION GASOLINE AND KEROSENE-BASE JET FUEL FROM MANDATORY PRICING AND ALLOCATION REGULATIONS

Analysis and Recommendations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Recommendations regarding exemption of aviation gasoline and kerosene-base jet fuel from mandatory pricing and allocation.

SUMMARY: On July 7, 1978, the Federal Energy Regulatory Commission published in the FEDERAL REGISTER AMENDMENTS to exempt aviation gasoline and kerosene-base jet fuel from mandatory pricing and allocation regulations. The amendments were issued by the Economic Regulatory Administration and were transmitted to FERC for its consideration and recommendations. This document reflects the views expressed in response to the Commission's notice as well as those expressed to ERA as a result of that agency's proposal.

DATE: Nonapplicable.

FOR FURTHER INFORMATION CONTACT: Robert L. Baum, Deputy General Counsel, Federal Energy Regulatory Commission, 202-275-4333.

SUPPLEMENTARY INFORMATION:

INTRODUCTION

SEPTEMBER 12, 1978.

On June 22, 1978, the Secretary of Energy transmitted to the Federal Energy Regulatory Commission certain amendments to the regulation under the Emergency Petroleum Allocation Act (EPAA) proposed by the Economic Regulatory Administration (ERA). Included were proposals to exempt aviation gasoline (avgas) and kerosene-base jet fuel (kerojet) from the mandatory petroleum allocation regulations as well as the mandatory petroleum price regulations. In order to take effect, an exemption from either the pricing or allocation regulations must be submitted to Congress as an "energy action." Under section 402(c)(1) of the DOE Act, the Commission is required to "consider" these proposals prior to submission to Congress by the Secretary.

At a Commission meeting on June 28, 1978, the Commission approved a FEDERAL REGISTER notice inviting comments and scheduling a public hearing on the proposals. The notice was published in the FEDERAL REGISTER on July 7, 1978, and established August 11, 1978, as the last day for written comments. A public hearing was scheduled and held on August 1 and 3.

The notice in the FEDERAL REGISTER indicated that the ERA had held public hearings and that the records of those hearings along with comments filed as a result of the ERA proposals would be available to the Commission. Accordingly, this summary reflects the views expressed in response to the Commission's notice as well as those expressed to ERA as a result of that Agency's proposal.

In order for a product to be exempted from the regulations the Secretary must find that the exemption is consistent with the attainment of public policy objectives in section 4(b)(1) of the EPAA. These objectives are as follows:

(A) Protection of public health (including the production of pharmaceuticals) safety and welfare (including maintenance of residential heating, such as individual homes, apartments, and similar occupied dwelling units), and the national defense;

(B) Maintenance of all public services (including facilities and services provided by municipally, cooperatively, or investor owned utilities or by any State or local government or authority, and including transportation facilities and services which serve the public at large);

(C) Maintenance of agricultural operations, including farming, ranching, dairy, and fishing activities, and services directly related thereto;

(D) Preservation of an economically sound and competitive petroleum industry; including the priority needs to restore and foster competition in the producing, refining, distribution, marketing, and petrochemical sectors of such industry, and to preserve the competitive viability of independent refiners, small refiners, nonbranded independent marketers, and branded independent marketers;

(E) The allocation of suitable types, grades, and quality of crude oil to refineries in the United States to permit such refineries to operate at full capacity;

(F) Equitable distribution of crude oil, residual fuel oil, and refined petroleum products at equitable prices among all regions and areas of the United States and sectors of the petroleum industry, including independent refiners, small refiners, nonbranded independent marketers, branded independent marketers, and among all users;

(G) Allocation of residual fuel oil and refined petroleum products in such amounts and in such manner as may be necessary for the maintenance of, exploration for, and production or extraction of—

(ii) Minerals essential to the requirements of the United States, and for required transportation related thereto;

(H) Economic efficiency; and

(I) Minimization of economic distortion, inflexibility, and unnecessary interference with market mechanisms.

In addition, section 12 of the EPAA provides that any amendment submitted to congress which proposes an exemption from the allocation regulations be accompanied by a finding that the product is no longer in short supply and the exemption would not have an adverse effect on the supply of any other oil or product. The exemption from the price regulations must be accompanied by findings that competition and market forces would provide adequate protection for the consumer and that such amendment would not result in inequitable prices for any class of user. The exemption also must be accompanied by an analysis of the potential economic impact of such amendment.

The Secretary has: (a) determined that the exemptions are consistent with the public policy objectives in § 4(b)(1) of the EPAA (supra), (b) found that avgas and kerojet are no longer in short supply and that exempting them from the pricing and allocation regulations would not have an adverse effect on the supply of oil or other refined products, (c) found that competition and market forces will provide adequate protection for the consumer and the exemption will not result in inequitable prices for any class of user, and (d) provided an analysis of the potential economic impact of the proposed exemptions. It is these issues which the Commission must now consider.

Although a representative of the Secretary made oral presentations at the hearings, the basis for the Secretary's determinations and findings is contained in documents entitled "Findings and Views Concerning the Exemption of Aviation Gasoline from the Mandatory Petroleum Allocation and Price Regulations, June 1978," and "finding and Views Concerning the Exemption of Kerojet Fuels from the Mandatory Petroleum Allocation and Price Regulations—June 1978." These documents were made available to interested persons in this proceeding. Earlier drafts were made available to the public at the time of the ERA proposal. At that time they were ERA's "Preliminary Findings." Subsequent to review of the comments and oral statements in that Agency's proceedings, the drafts were revised as a final report.

In addition to a general discussion of avgas and kerojet industries and history of price controls, supply and demand trends, etc., the final reports contain the technical information which the Secretary believes supports the determination and findings which must accompany the exemption.

PUBLIC RECORD

ERA PROPOSAL

ERA, after detailed analysis of avgas and kerojet and after consideration of comments on their preliminary findings, proposes to exempt avgas and kerojet from price and allocation control with no transition program and with no monitoring of prices.

HEARINGS AND COMMENTS

The FERC held public hearings on the ERA proposals on August 1, 1978 (covering avgas), and August 3, 1978 (covering kerojet). Four parties commented orally on avgas and seven on kerojet. In addi-

tion 51 parties presented comments in writing.

The record also includes the ERA hearing of March 22, 1978, on avgas where there were 7 commentors and March 23, 1978, on kerojet when 18 speakers participated. ERA's record also includes 44 written comments on exemption of avgas from controls and 50 on kerojet exemption. A tabulation of the comments shows the scope of participation:

Comments on Avgas and Kerojet Exemption

	To ERA				To FERC			
	Oral		Written		Oral		Written	Total ERA and FERC*
	Avgas	Kerojet	Avgas	Kerojet	Avgas	Kerojet		
FBO's**	1	1	23	21	1	1	27	48
Oil companies	4	11	11	15	1	2	13	26
Airlines	—	2	—	3	—	—	8	9
Trade associations	2	4	5	5	1	3	—	10
State and Federal Government	—	—	4	4	1	1	2	6
Consumers	—	—	1	2	—	—	—	2
Consultants	—	—	—	—	—	—	1	1
Total	7	18	44	50	4	7	51	102

*Excludes duplicate counting of parties who presented their comments more than once.
**FBO's (fixed base operators) are vendors of aviation fuels to general customers at air fields.

None of the oral or written comments to the FERC or to ERA expressed opposition to the proposal although there were some suggestions for modifications. A large majority of the written comments merely expressed support for the proposal; some few provided additional factual material or added analysis to supplement the ERA work.

In spite of the overwhelming support for the proposal we feel that the dissenting suggestions merit more than cursory consideration. Of particular concern are:

1. The concern of the Energy Planning Division of the Montana Department of Natural Resources and Conservation (Montana) in their letter of July 26, 1978, to the Commission that the supply of aviation products appeared sufficient in the spring but there is now difficulty for FBO's to obtain supplies. Adequacy of supplies for forest firefighting and other emergency situations is their expressed immediate concern. Although this is the only mention of this type problem, it cannot be ignored.

2. The International Air Transport Association (IATA) claims, in their oral presentation to the FERC on August 3, 1978, that there is a need to provide air carriers with a safeguard of supply. In doing so they repeat points made to the ERA on March 23. A similar position was taken by Pacific Southwest Airlines in its August 4, 1978, letter to the Commission. Also, the Air Transport Association of America (ATA) and United Airlines in statements to the ERA on March 23 took the same position. ATA and United in letters to the Commission, asked that their previous testimony be considered although both emphasized the need to complete action by the end of this year.

These positions represent the two most significant differences from the ERA recommendation and although they are minority points of view they will be considered in our analysis.

Aviation Gasoline

ERA Conclusions

ERA's analysis of the supply and demand for aviation gasoline is contained in "Findings and Views Concerning the Exemption of Aviation Gasoline from the Mandatory Petroleum Allocation and Price Regulations" (U.S. Department of Energy, Economic Regulatory Administration, June 1978 DOE/ERA 002) and pages 3-36 in the transcript of the August 1 hearing before the FERC in this docket. ERA's recommendation for exemption from price and allocation control is based on their conclusions that:

1. Aviation gasoline is not in short supply and anticipated supplies will be sufficient to meet the demand through 1979. Similarly, stocks of aviation gasoline are sufficient to meet demand surges.

2. Adequate capacity exists to meet the demand for aviation gasoline and all other refined products, except for residual fuel oil and refineries have the flexibility to satisfy this demand.

3. Competition and market forces are adequate to protect consumers if aviation gasoline is exempted from regulations.

4. No major price increases for aviation gasoline are expected to occur solely as a result of exemption.

5. Exemption would not result in inequitable prices for any class of end-user.

With these conclusions, they find that their recommendation is consistent with the attainment of the objectives in section 4(b)(1) of the Emergency Petroleum Allocation Act of 1973 (EPAA). They also present views on potential impacts of the exemption as required by section 12(d)(2)(A) of the EPAA in which they anticipate:

1. No significant State or regional impacts.

2. No adverse impact on the availability of consumer goods and services.

3. An insignificant effect on the gross national product.

4. No adverse effect on the competitive viability of independent refiners and marketers.

5. No adverse effect on small business.

6. No effect on the supply of fuel and feedstock for industry.

7. A negligible impact on the rate of unemployment.

ANALYSIS AND EVALUATION

1. *Supply and demand.* ERA's conclusions depend on the adequacy of supply to meet demand. Domestic demand for aviation gasoline in 1977 increased by about 4½ percent—the first increase in about 20 years. ERA's analysis of the avgas market leads them to conclude that the increase in 1977 represents a change in the trend and that continued small increases may be expected in the next few years. A review of the composition of the avgas market supports this conclusion.

Aviation gasoline serves customers in four end-use categories: general aviation (corporation aircraft, personal flying, air charters, air taxis, commuter airlines, and civilian government flying), military, commercial airlines, and factory use.

The largest part of the present market is in general aviation. This market, served by fixed-base operators (FBO's) is the only end-use that has shown any growth in recent years and it now accounts for about 80 percent of the avgas market. Slightly less than half of the general aviation fuel requirements are avgas and it is in this part of the market that requirements are expected to increase.

In the general aviation category, almost three-fourths of the operations are for business purposes, about one-quarter for personal flying and 2 percent is classified as "other flying." Business aircraft use is continuing to grow and there is no indication of a decline in the popularity of personal flying. Corporate aircraft use a considerable amount of jet fuel but still require avgas for some operations.

Military use which represented the largest market for avgas 10 years ago (after most commercial airlines switched to jet fuel) has also converted to jet to a large extent. Less than 10 percent of the military aviation fuel is avgas and the military market accounts for about 15 percent of avgas sales.

Commercial airlines' switch from piston-engined aircraft to jet-powered equipment has been the the largest factor in the long-term decline of avgas use and this switch has about been completed. Now less than 1 percent of the commercial airlines' fuel is avgas, and this accounts for 6 percent of the total avgas market.

During the period of a declining market for aviation gasoline no major shortage problems have been recorded. Spot shortages have existed, particularly for low octane avgas. DOE regulations only apply to adequacy of supply of total aviation gasolines so the problems of shortages of a specific quality of aviation gasoline have been solved by refiners' voluntary response to DOE requests and by their response to their customers' needs.

With the exception of the spot shortages noted above, the supply appears to have been adequate and none of the FBO's have complained to ERA or FERC of serious shortages. There is a tendency to attribute any shortages to regulation and FBO's seem to expect the free market to be able to answer any supply problems.

FBO's show faith in their suppliers. The only supply evidence they present is the statement by their suppliers (the refiners) that supplies will be adequate. Some refiners have publicly stated that they will continue to supply customers for at least a year if they can't get a new supplier in that period. This has been interpreted by some spokesmen to indicate that all suppliers will adopt this policy in spite of the fact that some are known to plan to abandon markets as soon as they can.

Most refiners oppose a transitional supply arrangement similar to special rule 4 for motor gasoline, but none indicated they would find it intolerable. Refiners also oppose any form of price monitoring that would include provisions for automatic return to controls (monitoring with triggering). They do not object to DOE following price data or requiring reasonable reports to enable the monitoring of price trends (monitoring without triggering).

2. *Product specifications.* Aviation gasoline comes from the same part of the barrel as motor gasoline; currently about 45 percent of the refinery output is motor gasoline and about 0.3 percent is aviation gasoline. No aviation gasoline is imported at this time and no imports are expected.

Aviation gasoline was at one time available in five grades:

Grade (octane or performance number) and *Current Status*

80/87—Available; sometimes in short supply; some refiners want to phase it out.

91/98—Discontinued.

100/130—Available.

108/135—Discontinued.

115/145—Now a specialty product, available in only a few locations.

100/130 LL (low lead)—A new product designed to provide performance required for both 80/87 and 100/130.

There is a performance and/or maintenance penalty for using the wrong quality gasoline in most airplanes. Refiners have developed grade 100/130 low-lead because it reduces the problems caused by using 100/130 leaded gasoline in planes designed for 80/87 octane. It has not proven a completely satisfactory substitute and there have been numerous reports that 100/130 LL is damaging engines designed for grade 80/87.

Aircraft manufacturers, owners, and pilots seem to have adjusted to the discontinuation of production of 91/98 and 108/135 grades and it is possible that one all-purpose grade will be developed. Most, if not all, new aircraft are designed for 100/130 LL.

3. *Refinery capacity.* Aviation gasoline quality requirements are stricter than those for motor gasoline but not necessarily higher in octane rating. The potential supply for aviation gasoline is limited by the quality requirements and by the availability of refinery facilities to provide product that meets specifications. Aviation gasoline specifications that may cause problems are octane requirements, additive requirement, and more precise quality control. The components of aviation gasoline are produced in the same facilities that produce motor gasoline and the adequacy of industry capacity will depend on the developments in motor gasoline rather than aviation gasoline. Less than 1 percent of the gasoline output from American refineries goes into aviation gasoline.

The development of one all-purpose grade of aviation gasoline, such as 100/130 low lead, would relieve supply problems of FBO's. It would, however, seem to aggravate supply problems of refiners since this step would require more high-octane unleaded components for aviation gasoline. It is the requirement for more high-octane unleaded components for motor gasoline that presents the major potential supply problem for that market. The grade to be phased out—80/87 octane leaded—should present no supply problems to refiners; it is, however, this product that has been in short supply while no problems in 100/130 low lead have been reported.

From the record, however, it seems clear that the Nation's total aviation gasoline supply will be adequate to meet needs if there are no major problems in total gasoline supply. There can, however, be supply problems in one specific grade, and, as noted in paragraph 5 below, there can be regional problems.

4. *Competition and prices.* FBO's expect there will be more competition

among their suppliers with decontrol; ERA, on the other hand, looks for competition to remain about constant. There are indications that refiners will pull out from certain markets after controls are lifted but FBO's seem to feel that this step will enable refiners to supply other areas more efficiently and that new marketers will move in.

No complaints were received that prices are, or will be, too high. FBO's feel that competition limits their prices and only in some high-cost markets are they now at ceiling prices. ERA expects that FBO prices will increase as much as 4 cents per gallon in some areas and 1½ cents per gallon on the average because of the lifting of controls. No estimate was provided concerning the change in price at refineries, but ERA indicates that prior to control, avgas prices paralleled motor gasoline prices. It would seem reasonable to expect the same pattern to follow after decontrol. In their presentation on motor gasoline decontrol, ERA projected a 1 cent per gallon increase in motor gasoline prices due to decontrol. If this increase carries through to aviation gasoline, there may be an additional 1 cent increase if both motor gasoline and aviation gasoline are freed from control; this would represent a 11.5 percent increase (avgas now priced at 70 cents–$1 per gallon). Such an increase would be consistent with analyses by refiners.

5. *Objectives of section 4(b)(1) of the EPAA.* ERA analyzes the results of exemption of avgas as follows:

It is DOE's finding that the exemption of aviation gasoline from the price and allocation regulations is consistent with the attainment of the objectives set forth in section 4(b)(1) of the EPAA. Since an adequate supply is anticipated, the continued allocation and pricing control of aviation gasoline are not necessary to protect the public health, safety, and welfare and the national defense (section 4(b)(1)(A); the maintenance of all public services (section 4(b)(1)(B)); the maintenance of agricultural operations (section 4(b)(1)(C)); or the maintenance of exploration for the production or extraction of fuels and minerals (section 4(b)(1)(G)). Adequate supply and the positive effects of increased competition should insure that an exemption is consistent with the preservation of an economically sound and competitive petroleum industry (section 4(b)(1)(D)); the equitable distribution of crude oil, residual fuel oil, and refined petroleum products at equitable prices (section 4(b)(1)(F)); economic efficiency (section 4(b)(1)(H)); and the minimization of economic distortions, inflexibility, and interference with market mechanisms (section 4(b)(1)(I)). An exemption should have no adverse effect on the allocation of suitable crude oil to U.S. refineries (section 4(b)(1)(E)).

The ERA analysis is consistent with the record available from their March hearing. However, the Montana letter, noted above, offers a different viewpoint that would lead to different conclusions. Certainly there can be little doubt that overall supply is adequate and that any shortages would be localized. The ERA study admits to the possibility of local shortages so there is no inconsistency between the Montana evaluation of the supply situation and the ERA evaluation It is the significance of local shortages that is of concern.

If local shortages represent inconveniences they are unfortunate; if they result in inability to meet an emergency they are intolerable and mean that this proposal, as presented, does not meet the requirements of section 4(b)(1)(A) of the EPAA to protect public health, safety, and welfare and section 4(b)(1)(B) to maintain all public services.

The problems raised by Montana were not presented to ERA in March when their hearings were held and, therefore, they have not been addressed by the ERA. Nor has any other party commented on this problem. We cannot be certain whether this is a problem unique to the State of Montana or whether it exists elsewhere but has not been reported. In any event, it seems proper to consider providing relief for such situations where they exist.

6. *Potential economic impacts.*—(a) *State and regional impacts.* DOE expects no State or regional impact. No participant presented any State or regional analysis to show adverse impact in any specific area but, as noted in paragraph 5 above, the Montana State Fuel Allocation Office pointed out that small remote FBO's could face problems that could adversely affect economic activity there.

The airplane is more important to the economic activity of sparsely populated areas where considerable distances must be covered in a normal working day than it is in densely populated areas. In the less populated areas, the use of aviation gasoline may not be large and the markets may be unattractive to suppliers. Therefore, the problem noted by Montana may have an economic impact to be considered. Provisions to accommodate the problem noted in paragraph 5 above would cover this problem to the extent it exists.

(b) *Availability of consumer goods.* ERA's conclusion that the exemption will have no adverse impact on the availability of consumer goods and services appears justified.

(c) *Competition.* ERA's conclusion that the exception will not adversely affect the competition viability of independent refiners and marketers seems justified.

(d) *Effect on small business.* ERA concludes that "an exemption * * * would not adversely affect small business." No comment received by ERA or FERC from refiners or FBO's would dispute this conclusion. To the extent this conclusion refers to small refiners (see paragraph 6c above) it seems justified. The FBO's are generally small businesses and, as noted in paragraphs 5 and 6a above, Montana feels they may be adversely affected in that State. This, however, would be a regional problem occurring in unusual instances and not a problem for all small businesses, or even for all small fixed base operators.

(e) *Supply of energy.* Aviation gasoline represents such a small part of our energy needs that its effect on supply and availability of energy will be negligible. Its use for commercial development of energy (company planes of energy companies) is not expected to suffer.

(f) *Unemployment, consumer price index, and gross national product.* The impact of aviation gasoline on national economic indicators will be small, as reported by ERA.

7. Price monitoring. The question of price monitoring was discussed by some parties. Generally it was opposed by refiners, ignored by FBO's and was requested by some airlines for jet fuel. ERA plans to continue to use existing price reporting systems until EIA's proposed price report form, EIA-12, is put into operation. This should provide adequate procedure to monitor prices (without triggering).

8. *Complaint procedures.* DOE currently has in operation a system for dealing with spot shortage problems in aviation gasoline. This system has proven to be an effective means of eliciting voluntary cooperation from suppliers to satisfy all needs. When free market forces take over and supplies move more freely, there should no longer be a need for this system, if the ERA analysis is correct. In the short run, however, this procedure should remain available as needed, and the method for handling problems of shortages should be made known to the public.

KEROSENE BASE JET FUEL

ERA CONCLUSIONS

ERA's analysis of the supply and demand for kerosene base jet fuel (Kerojet) is contained in "Findings and Views Concerning the Exemption of Kerojet Fuels from the Mandatory Petroleum Allocation and Price Regulations" (U.S. Department of Energy, Economic Regulatory Administration, June 1978, DOE/ERA-0001) and pages 134–184 in the transcript of the August 3 hearing before the FERC in this docket. ERA's recommendations for exemption from price and allocation control are based on the conclusions that:

1. Kerojet is not in short supply and anticipated supplies will be sufficient to meet the demand through 1979. Similarly stocks of kerojet are sufficient to meet demand surges.

2. Adequate refinery capacity exists to meet the demand for kerojet and all other refined petroleum products, except for residual fuel oil, and refineries have the flexibility to satisfy this demand.

3. Competition and market forces are adequate to protect consumers if kerojet is exempted from regulations.

4. Price increases for kerojet are not expected to exceed 1 cent per gallon solely as a result of the exemption.

5. Exemption would not result in inequitable prices for any class of end-user.

With these conclusions they find that their recommendation is consistent with the attainment of the objectives in section 4(b)(1) of the EPAA. They also present views on potential impacts of the exemption as required by section 12(d)(2)(A) of the EPAA in which they anticipate:

1. No significant State or regional impacts.

2. No adverse impact on the availability of consumer goods and services.

3. An insignificant effect on the gross national product.

4. No adverse effect on the competitive viability of independent refiners and marketers.

5. No adverse effect on small business.

6. No effect on the supply of fuel and feedstock for industry.

7. A negligible impact on the rate of unemployment.

ANALYSIS AND EVALUATION

1. *Supply and demand.* ERA recommendations are predicated upon an adequacy of supply. Kerojet requirements were growing at about 6½-7 percent per year prior to the oil embargo but in 1974 there was a drop in the domestic air activity. With the end of the embargo and the better supply situation some increase in kerojet demand has since been recorded and a 5 percent increase is projected by ERA.

The market for kerojet is 86 percent commercial airlines, 7 percent military, 5 percent general aviation, and 2 percent other.

The commercial airline market growth seems to follow past trends but may be understated. ERA points out that further action to deregulate airlines, now under consideration, could further accelerate kerojet demand. Military demand, now largely limited to carrier-based planes, could expand considerably beginning in 1979 if plans to switch all aircraft from naphthabase jet fuel to kerojet are realized.

General aviation demand for kerojet is divided between commuter airlines and corporate jets. There are no specific factors that herald a change in the outlook for those uses.

Demand for kerojet has not grown as rapidly as the demand for jet travel. Efficiencies and economies have been brought about by such developments as new equipment, larger aircraft, better load factors, and better scheduling. These steps have enabled airlines to increase their revenue ton-miles per unit of fuel. Some further improvements are expected but their impact has not been quantified; nor are they expected to match those of the recent past. The balance between growth and efficiency will determine the market and there is no evidence that the ERA outlook is not accurate.

The outlook for military demand for kerojet can cause some pressures on supply. If the military does convert all its operations from naphtha to kerojet it could bring about a need for 20 percent more kerojet beginning late next year. Such an increase in demand could put a strain on supply, but refiners, airlines and DOE are working to improve the supply situation either by a change in refinery yields or by developing a fuel for civilian aircraft that would include some naphtha (up to 30 percent) in the kerojet. If this step can be taken, it will eliminate the problem. Such a fuel would be interchangeable with kerojet and would not require modification of equipment.

2. *Refinery capability.* Jet fuel is available from U.S. refineries and from imports. Imports amounted to over 20 percent of our kerojet in 1973 and are projected to supply slightly more than 5 percent of our needs. With surplus foreign refining capacity it would appear that additional imports will be available if needed.

Prior to 1973 international airlines imported low cost kerojet in bond for flights to foreign countries. When foreign kerojet prices rose to make U.S. product cheaper, they switched to domestic kerojet and the cost of their imports was borne by the importers who passed it on to domestic as well as international airline customers. If there is an increase in kerojet prices following exemption, bonded imports may again be a factor in the supply-demand balance.

The major portion of the supply of kerojet under any circumstances will come from U.S. refineries. Kerojet is a highly refined kerosene; total refinery output of kerosene products have averaged less than 7 percent of crude runs, but yield can be increased to a maximum

potential yield of about 10 percent without special equipment. With sophisticated and costly secondary operations and appropriate crude oil, it is possible that a refinery can yield 14 percent kerojet fuel. The output of kerojet may increase because of changes in the gasoline market and increases are expected because of increased crude runs. The optimistic supply outlook is enhanced by the increased flexibility of American refineries.

Further improvement in supply would be achieved if the blending of naphtha with kerojet is allowed but even without such a step the potential supply is adequate. Adequacy of supply, of course, depends on availability of crude oil imports for processing at our refineries and availability of imported oil products to supplement our refinery output. ERA analysis shows that the foreign crude oil and products are available. Spot shortages are considered possible, particularly in PAD IV (Colorado, Idaho, Montana, Utah, and Wyoming) but recent pipeline additions seem to have relieved this problem.

3. *Competition and prices.* Large integrated refiners dominate the kerojet market and four of these supply more than 70 percent of the fuel to airlines. ERA maintains that capital demands restrict entry and does not expect any changes in competition but some refiners and other commentors consider controls to be the restrictive factor and expect additional entrants into the market if kerojet is exempt from controls. The parties purchasing kerojet note increasing interest upon the part of potential new suppliers and increased supply availability. Sun Oil Co. has indicated an interest in reentering the kerojet market and some other refiners have indicated plans to look for new markets. The record suggests that there will be more competition in the future, particularly if controls are lifted.

Competition will tend to keep prices from increasing but most of the record suggests that there will be some increases. ERA projects a price increase of 1 cent per gallon if kerojet is exempted (plus any increase in crude costs). Price increases of 1-3 cents are suggested by one FBO. Several refiners in testimony to the ERA alleged that refiners need incentives to increase the output of kerojet. Whether price decontrol would be an adequate incentive was not stated.

The purchasers of kerojet (civilian airlines and FBO's) all support decontrol and are not concerned that prices to them will increase to the detriment of their operations. From the record, it would seem that the increase in kerojet prices in response to the exemption would be less than 10 percent. This is based on a review of the ERA analysis which gives the only quantification in the record plus the comments by other parties.

Foreign prices can, in some cases, serve as a brake on increases in domestic prices. ERA estimates that there is about a 4-cent difference between U.S. and foreign kerojet prices. If the kerojet prices increase more than 10 percent, imports, including bonded fuel, can become competitive.

4. *Objectives of section 4(b)(1) of the EPAA.* The same considerations that apply to avgas seem to apply to kerojet. Montana refers to an aviation fuels supply problem; the provision for protection to FBO's who need supplies to avoid emergencies should be considered for both avgas and kerojet when local conditions demand such protection.

5. *Potential economic impact.* Kerojet represents a much larger part of our energy use than avgas and therefore its impact will be more noticeable. The potential increased supply in response to exemption seems to be economically beneficial even when balanced against the expected small price increase. Kerojet prices, as noted above, are expected to increase less than 10 percent; fuels account for about 20 percent of the airlines operating cost so the impact on airline costs would appear to be less than 2 percent.

Airline concern seems to emphasize supply and suggests that the economic impact of slightly higher fuel prices would be offset by the operating advantages of an uncontrolled source of supply.

6. *Monitoring and transition.* One big difference of opinion that shows up in the consideration of kerojet is the question of monitoring and transition controls. All refiners oppose monitoring although some provide suggestions for monitoring if it is to be instituted. Airlines and airline associations, on the other hand, tend to call for monitoring at the same time they ask

for decontrol. Transitional control is likewise opposed by refiners but supported by airlines; FBO's generally show no enthusiasm for either monitoring or controls.

ERA's opposition to monitoring is generally directed against monitoring with a trigger, a program for which there was no support in the record. ERA, either by itself or through EIA, will collect data that will enable it to follow price trends. Such monitoring without triggering is essential and should be part of the exemption program.

The transition program for kerojet seems to have less justification, except as noted in paragraph 4, above, for FBO's in unique circumstances. Airlines have demonstrated the ability to cope with supply problems and therefore it does not seem that they should need any transitional protection.

7. Complaint procedures. The record indicates that there is some confusion concerning the DOE method of handling complaints. DOE's present system has allowed for voluntary cooperation by suppliers to solve problems when this would prove more effective than operation of mandatory procedures. When free market forces take over and supplies move more freely, supply problems should be minimized, if ERA analysis is correct, and such a system may no longer be needed. In the short run, however, to provide for unforeseen events, this procedure should remain available as needed and the method of handling supply problems should be made known to the public.

CONCLUSION

The following correspondence sets forth the Commission's findings and conclusions and the final recommendation of the Commission.

By the Commission.

KENNETH F. PLUMB,
Secretary.

FEDERAL ENERGY REGULATORY COMMISSION

Washington, D.C., September 6, 1978.

Hon. JAMES R. SCHLESINGER,
Secretary, Department of Energy,
Washington, D.C.

DEAR MR. SECRETARY: On June 22, 1978, you forwarded to the Federal Energy Regulatory Commission certain proposed amendments to the regulations under the Emergency Petroleum Allocation Act (EPAA) that would exempt aviation gasoline and kerosene-based jet fuel (kerojet) from both the mandatory pricing and allocation regulations. The Commission has considered the proposed exemptions pursuant to Section 402(c)(1) of the Department of Energy Organization Act.

Based on our review of this matter the Commission has arrived at the conclusion that the methodology used to evaluate these matters is reasonable and the findings are appropriate. Accordingly, you are advised that the Commission has made the determination to concur in the proposals to exempt aviation gas and kerojet from the pricing and allocation regulations.

Although the data developed by the Economic Regulatory Administration (ERA) and the comments received by both the ERA and the FERC fully support the exemptions, both the data and the comments recognize that spot shortages of aviation fuels have existed and are likely to continue to exist. While the frequency and seriousness of these shortages cannot be accurately predicted, they remain a matter of concern.

The State of Montana's Department of Natural Resources and Conservation has submitted comments indicating that although supplies of "aviation products" appeared sufficient until recently, at the present time some fixed base operators in that State are having difficulty in obtaining suppliers. The letter (copy attached) was apparently not available to the ERA during its consideration of this matter. In addition, in both the ERA proceeding and proceedings before the Commission, the commercial airlines, although favoring the exemptions, request both a monitoring program and transitional controls for kerosene-based jet fuel.

In connection with the monitoring system, it is generally agreed that such a program should not contain a "trigger". In view of ERA's expressed intention to generally monitor prices of aviation fuel, the Commission does not conclude that a recommendation within the contemplation of §404(b) and §404(c) of the DOE Act is necessary. However, the Commission believes that a monitoring program should be announced as part of the ex-

emption and should be fully described by the ERA if the proposals are forwarded to Congress.

The possibility of a transitional program presents different problems. In this connection, the Commission is interested in the legal and administrative feasibility of a program more limited than Special Rule No. 4, adopted in connection with the exemption of motor gasoline. More specifically the Commission believes that you should consider the possibility of a program applicable only to certain areas of the county. In this regard you may wish to examine whether such a program could be provided only upon request of a State or a State Energy office.

You are advised that the Commission has instructed the Secretary of the Commission to forward to you a letter stating its concurrence without recommendations in this proposal, unless, by noon, Friday, September 8, 1978, you advise the Commission that you wish to consult on any matter set forth in this letter.

Sincerely,

CHARLES B. CURTIS
Chairman.

MONTANA DEPARTMENT OF NATURAL RESOURCES & CONSERVATION,
July 26, 1978.

Re Exemption of Aviation Jet Fuel and Gasoline from Federal Price and Allocation Regulation.

DEPARTMENT OF ENERGY,
FEDERAL ENERGY REGULATORY COMMISSION,
Washington, D.C.

Attn: Commission Secretary.

GENTLEMEN: The Montana State Fuel Allocation Office (MSFAO) hereby submits comments on removal of aviation products from price and allocation controls as noted in the July 3, 1978 Federal Energy Regulatory Commission (FERC) news release.

The MSFAO has closely followed DOE's aviation decontrol proceedings. The supply of aviation products appeared sufficient in Montana until approximately two months ago. Now, new fixed base operators are having difficulty obtaining suppliers. In addition, many small, established fixed-base operators are unable to secure priority fuel increases because of major oil company exchange problems.

Presently, the MSFAO understands that Phillips Petroleum Co. is unable to obtain aviation fuel from the Denver or Salt Lake City areas. If this is indeed the situation, DOE's findings of supply sufficiency are in error. Of immediate concern is the adequacy of supplies for forest fire fighting and other emergency situations. DOE, under the current regulations, has appointed Region X as the emergency aviation fuel problem center for such situations in the Pacific Northwest. When decontrol is achieved, how will these emergencies be handled?

Because of major oil company withdrawals from the Montana marketing area, aviation fuel exchange capabilities will be greatly reduced with decontrol. Consequently, the small rural fixed-base operators will have a difficult time procuring supplies.

Prior to aviation fuel decontrol, the MSFAO hereby petitions FERC to investigate the above situations and provide emergency measures to deal with supply availability for fire fighting and small, fixed base operations.

Sincerely,

JOHN C. BRAUNBECK,
Fuel Allocation,
Montana Energy Division, DNRC.

DEPARTMENT OF ENERGY,
September 11, 1978.

Hon. CHARLES B. CURTIS,
Chairman, Federal Energy Regulatory Commission, Washington, D.C.

DEAR MR. CHAIRMAN: This is in response to your letter of September 6, 1978 to Secretary Schlesinger indicating the Commission's concurrence in the Secretary's proposal to exempt aviation fuel and kerosene-base jet fuel from mandatory price and allocation regulations. We appreciate the Commission's comments and suggestions regarding a price monitoring system and a transitional product allocation program to deal with localized shortages and will take these views into account in developing a final decontrol action. In light of the fact that the Commission's concurrence in the rule proposed by the Secretary is not subject to any recommendations within the meaning of

READEX Fiche

Section 404(b) of the Department of Energy Organization Act, I do not believe any further consultation beyond this exchange of letters is necessary.

Sincerely,

JOHN F. O'LEARY,

Deputy Secretary.

¶ 31,996 Incentive Rate of Return for the Alaska Natural Gas Transportation System

43 F.R. 45595 (October 3, 1978).

[18 CFR Chapter 1]

[Docket No. RM78-12]

INCENTIVE RATE OF RETURN FOR THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Revised Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: The Federal Energy Regulatory Commission (the Commission) hereby gives notice of a revised proposal to establish certain terms and conditions to the conditional certificates of public convenience and necessity previously issued in the Alaska Natural Gas Transportation System proceedings (Docket Nos. CP78-123, CP78-124, and CP78-125). The proposed terms and conditions would establish an incentive rate of return on equity to reward the applicants for final certificates for project completion under budgeted cost and penalize them for project completion over budgeted cost.

DATE: Written comments by October 6, 1978.

ADDRESS: All filings should reference Docket No. RM78-12 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C.,20426.

FOR FURTHER INFORMATION CONTACT: John Adger, Director, Alaska Natural Gas Project Office, Federal Energy Regulatory Commission, 825 North Capitol Street NE, Washington, D.C. 20426, 202-275-3827.

U.S. FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Charles B. Curtis, Chairman; Don S. Smith, Georgiana Sheldon; Matthew Holden; and George R. Hall.

Incentive Rate of Return for The Alaska Natural Gas Transportation System—Docket No. RM78-12.

REVISED NOTICE OF PROPOSED RULEMAKING

(Issued Sept. 15, 1978)

Notice is hereby given, pursuant to the Administrative Procedure Act (5 U.S.C. 553), the Natural Gas Act, sections 4, 5, 7, and 16 (15 U.S.C. 717c, 717d, 717f, and 717o), and the Alaska Natural Gas Transportation Act, section 9 (15 U.S.C. 719g), that the Federal Energy Regulatory Commission (Commission) is considering the adoption of revised terms and conditions concerning an incentive rate of return (IROR) on equity for the certificates of public convenience and necessity for the Alaska Natural Gas Transportation System (ANGTS). Conditional certificates were issued by the Commission on December 16, 1977, *Alcan Pipeline Company, et al.*, Docket No. CP78-123, CP78-124, and CP78-125).

On May 8, 1978, in a notice of proposed rulemaking, the Commission announced that it is considering the adoption of terms and conditions concerning an IROR on equity for the certificates of public convenience and necessity for the ANGTS.[1] In this notice, the Commission invited interested parties to submit written comments on the proposed rule by May 31, 1978. By notice issued May 26, this comment period was extended to June 14, 1978. Parties were also allowed to file reply comments by June 23, 1978. Though some of these comments were received after the extension period, the Commission has considered all of the comments in revising the terms and conditions first proposed in the May 8 notice.

The Commission will entertain further comments from interested parties on the revised terms and conditions presented herein. An abbreviated comment period is provided, for the Commission intends expeditious adoption of the proposed rule.

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TERMS AND CONDITIONS—ATTACHMENT

I. INTRODUCTION

The Commission received 24 comments on the proposed rulemaking from interested parties. Two comments were received from the Commission staff: One from the Office of Regulatory Analysis and another from the Office of Pipeline and Producer Regulation.

Three State governments or regulatory agencies filed comments: The State of Alaska, the State of California and the Public Utilities Commission of the State of California, and the Public Service Commission of the State of New York.

Three comments were received from companies that have applied for certificates to build and operate a segment of the ANGTS: Alaskan Northwest Natural Gas Transportation Co., Northern Border Pipeline Co., and Pacific Gas Transmission Co. and Pacific Interstate Transmission Co.

Twelve comments were received from other interstate natural gas pipeline companies: Columbia Gas Transmission Corp., Michigan Wisconsin Pipeline Co., Northern Natural Gas Co., Natural Gas Pipeline Co., Northwest Pipeline Co., Panhandle Eastern Pipe Line Co., Texas Gas Transmission Corp., Tennessee Gas Pipeline Co. and Midwestern Gas Transmission Co., Transcontinental Gas Pipe Line Co., Texas Eastern Transmission Corp. and Trans-Western Pipeline Co., Texas Gas Transmission Corp., and United Gas Pipe Line Co.

Four comments were received from other interested parties: The American Gas Association, the Southern California Edison Co., the Upper Tanana Development Corp., and the Williams Bro. Engineering Co.

Having evaluated these comments, the Commission issues this revised notice in order to incorporate improvements suggested by valid criticisms and to respond to criticisms with which the Commission does not agree. In addition, this revision includes further discussion of the concept and design of the IROR, in order to

clarify the IROR proposal and to establish a common conceptual ground for further comment.

The revised proposal includes five changes to the terms and conditions originally proposed in the May 8 notice:

1. Certain concepts have been restated to make them more readily understood.

2. The method of adjusting for inflation in determining the cost performance ratio has been altered to more equitably remove the effects of inflation from the workings of the IROR.

3. The condition listing certain changes in scope for the project has been deleted. The subject of changes in the scope is a matter of utmost importance but will require further time to resolve; therefore the Commission will consider it in a separate rulemaking to be initiated as soon as appropriate staff work and studies have been completed.

4. The one-time adjustment to the rate base will be calculated so as to account for the entire difference between the incentive rate of return and the equity rate that would be earned on a pipeline of comparable operating risk.

5. Application of the IROR concept to the Western Leg has been dropped.

In addition to these changes in terms and conditions, this notice of proposed rulemaking invites comment on a revised IROR schedule which the Commission believes to be more realistic than those examples set forth in the previous notice. The actual values that will apply, as well as the permissible rates of return based thereon, of course, must be evaluated and determined in an evidentiary proceeding.

The construction of the example is also based on the assumptions that (1) the final cost estimates filed with the Commission, after adjustment for inflation and changes in pipeline design and routing, will not differ significantly from those submitted in March 1977, and (2) the separate change of scope rulemaking will not significantly reduce the risk borne by the project sponsors. Any changes in that risk must lead to corresponding changes in the allowed compensation for bearing such risk.

II. THE INCENTIVE RATE OF RETURN CONCEPT

A. *Purpose of an incentive rate of return*

The President's *Decision* on the Alaska Natural Gas Transportation System mandates the use of an incentive rate of return (IROR) to deter cost overruns during the construction of this project.

The traditional tool for cost control in pipeline construction has been regulatory oversight, with the attendant threat of disallowing any investment imprudently incurred during construction of this project.

The traditional tool for cost control in pipeline construction has been regulatory oversight, with the attendant threat of disallowing any investment imprudently incurred during construction. Such a regulatory approach, however, is a blunt instrument that is effective only to counteract extreme cases of management's lack of foresight or diligence. Before any costs may be disallowed from the rate base they must be shown to have been imprudently incurred, which implies that only those costs attributable to patently unreasonable management action may be disallowed.

A regulated utility has an economic incentive to increase its return by expanding its rate base and the negative incentive to avoid disallowance of imprudently incurred costs.[2] Better cost-control awareness should be obtained by providing as an incentive for the utility the reward of a greater return. This sort of incentive operates for competitive industries but is generally absent under conventional utility regulation.

The economic impetus toward cost control will be achieved by tying the allowed rate of return to the degree of cost overrun experienced on the project: superior cost control will be rewarded with a higher rate of return. The IROR is designed to complement the disallowance of costs mechanism by offering economic rewards for holding down all costs. Thus, project managers will be rewarded for eliminating costs which are avoidable, even though the costs, if incurred, would later have been classified as "prudent." Without IROR, all prudent costs would simply be included in the rate base, and there would be only the most general impetus to attain superior cost control. With the economic incentives embodied

in the IROR, the project sponsors will find it in their own interest to seek out and use opportunities to reduce any construction costs that could be reduced. Project managers are in a much better position to detect such opportunities than is the Commission, and the degree of regulatory oversight can be scaled down.[3]

Under the conventional regulation approach, consumers are forced to bear all the costs of overruns, since increased costs may be required to be added to the rate base. Under the IROR policy, however, the burden of cost overruns will be distributed between consumers and equity investors. Investors, the group to which management must answer, will benefit from superior cost-control results. Also, the consumer interest will be served by assurance that there is a sharing of the risks of cost overruns.

In sum, the IROR should lead to savings in construction costs, which will be divided between lower costs to consumers and higher returns to investors as a reward for cost control. Thus, the ultimate effect of applying IROR to hold down costs will be to provide lowercost gas to consumers and just and reasonable returns to investors.

To reach this goal, the Commission proposes to incorporate the following principles for designing the IROR, each of which is discussed more fully in later sections:

(1) The IROR must provide incentives to reward cost control performance and avoid or minimize cost overruns.

(2) The IROR must provide just and reasonable compensation for investors, in order that sufficient capital may be attracted to finance the project.

(3) The cost to consumers should be lower where cost overruns have been minimized and investors have been awarded an incentive return.

B. *Establishing an incentive rate of return schedule*

The Commission, in the rulemaking here proposed, will design the IROR schedule so as to accomplish the goals of the rulemaking. The design consists quite simply of attaching a separate rate of return to each level of cost control performance. Careful consideration is required in order to design an effective schedule that will yield the desired effect.

1. *Benchmark rates of return and risk premiums.* As a starting point for setting the IROR schedule, certain rates of return can be used as benchmarks. These benchmark rates of return are specifically linked to the various types of unusual risk facing this project.

a. *Operation phase rate.* This is the rate of return to be allowed on the adjusted rate base. It is a starting point for determining the actual incentive rate that will be allowed. This rate should be the rate allowed on pipelines of similar operating risk without allowance for any special construction and completion risks of the Alaska pipeline. (These risks are compensated for with the nonincentive rate, described below.)

b. *Nonincentive rate.*[4] This rate is arrived at after evaluating the special risks inherent in the Alaska project. It equals the sum of the operation phase rate and a project risk premium for those construction and completion risks unique to the Alaska pipeline project. This rate, which does not account for the IROR risk, is the rate which would be granted after conventional regulatory proceedings.

c. *Center rate.* The center rate includes compensation for all risks associated with the project. Specifically, it reflects the operation phase rate, the project risk premium, and the IROR risk premium. (The center rate is equivalent to the nonincentive rate plus the IROR risk premium.) The IROR risk premium is to compensate investors for the risk introduced by the variability in the allowed rate of return implied by adoption of IROR. The center rate will be earned if actual project costs equal the forecasted level of cost overruns, after adjustment for inflation and changes in scope (the subject of a separate proceeding).

In establishing these benchmark rates of return, the Commission's primary consideration will be to determine the just compensation for bearing the risks of this project. These risks are affected by (among other factors);

The type of cost-of-service tariff to be granted for this project;

The beneficial effect on marketability of the Alaskan gas if its cost is rolled in with the cost of other gas;

The unusual construction and noncompletion risks faced by this pipeline;

The financial plan and final capital structure developed by the project sponsors;

The variability in allowed rates of return imposed by the IROR; and

The degree of flexibility allowed in adjusting estimated costs.

2. *Cost performance ratio.*[5] The cost performance ratio is an index of the degree of cost overruns or underruns. It is simply the ratio of actual construction costs, including an allowance for funds used during construction (adjusted for inflation), divided by estimated construction costs (adjusted for any changes in scope): Cost performance ratio equals actual costs divided by estimated costs equals deflated actual rate base divided by projected rate base.

In the proposal, this is the ratio between the deflated actual rate base and the projected rate base as defined in the conditions below. The deflated actual rate base is derived from the actual construction costs and schedule according to standard procedures followed by all pipelines, and includes the allowance for funds used during construction (AFUDC). The projected rate base is the rate base derived from the final cost and schedule estimates submitted by the applicants.

The IROR schedule relates a rate of return to each cost performance ratio. As the ratio increases, signifying overruns, the associated rate of return decreases.

3. *The marginal rate of return.*—a. *The concept of the marginal rate.* Any schedule relating increased costs to the allowed rate of return on equity established by this Commission (the IROR schedule) will imply or define at least one marginal rate of return. This Commission must consider that marginal rate in order to determine the cost-control incentive created by the schedule. Similarly, equity investors or project sponsors must consider the implicit marginal rate in order to determine the rewards available to them for holding down cost overruns. The relationship of the marginal rate to the investors' cost of capital determines the amount of effort that is economically justified to avoid cost overruns.

The marginal return is the return on the incremental dollars invested to move from cost performance ratio to another. To illustrate:

Cost Ratio and Allowed ROR

1.2—17.8 percent.

1.3—17.0 percent.

1.4—16.4 percent.

Assume that the ratio of 1.3 has already been reached shortly before project completion. Then, in order to complete the project, more funds must be invested and a ratio of 1.4 must be reached. If the project had been completed at 1.3 (30 percent overrun), the allowed ROR would have been 17.0 percent. Since the project may actually be completed at 1.4 (40 percent overrun), the allowed ROR on all equity is decreased to 16.4 percent. Given these rates of return, it follows that the actual return earned on the additional dollars invested to move from 1.3 to 1.4 (regarded as $1.3 and $1.4 million, the incremental investment is then $0.1 million) is 8 percent. This results from the following calculation:

(earnings at 1.4)—(earnings at 1.3)/increase in rate base(1.4)(.1636)—(1.3)(.17)/1.4—1.3-0.08-8 percent marginal return.

Once again, the rate of return on the additional $0.1 million is 8.0 percent even though the rate of return on the entire $1.4 million is 16.4 percent.

b. *The importance of the marginal rate.* The investors seek to invest funds so as to earn a rate of return higher than the cost of the capital. If capital costs more than an investment earns, then that investment will not be made.

An investor's profits will be maximized only when each unit of capital invested is itself as profitable as possible. The project sponsors plan to assemble a pool of capital large enough to finance any degree of cost overrun which has a substantial probability. A marginal rate below the cost of capital will give the project sponsors an extra incentive to avoid having to finance the overrun in order to insure that parts of that pool will be available for future projects whenever possible.

Under IROR, an investor faced with the prospect of financing cost overruns will examine the return on his investment of the additional unit of capital necessary to pay for the overrun. If he finds that

return to be lower than his cost of capital, he will strive to avoid having to undertake the investment which the overrun requires.

The marginal rate must be set below investor's cost of capital if the IROR is to offer rewards for reducing overruns. If the marginal rate were above the cost of capital, then overruns might be attractive equity investments, and the IROR would have failed its primary purpose.

The marginal rate, and thus the degree of incentive, can be set independently of the center rate. An IROR schedule can maintain the same incentive to control costs, even though the overall level of compensation in the schedule might be moved up or down.

Since the calculation of the cost performances ratio includes the AFUDC, a low marginal rate also provides incentives for avoiding construction delays. If construction is delayed, the AFUDC account grows. This raises the deflated actual rate base and the cost performance ratio, with a corresponding decline in the allowed rate of return. Therefore, meeting the construction schedule will avoid penalties in much the same way as does reducing cost overruns.

4. *The center point.* One of the cost performance ratios must be chosen as the starting point for constructing the IROR schedule. Once that point has been assigned a rate of return, and the marginal rate has been chosen, the entire schedule can be determined.

The center point is that cost performance ratio which is associated with the center rate of return. Ratios above the center point will yield rates of return below the center rate. Ratios below the center point will be rewarded as underruns, with rates of return greater than the center rate.

In order for the center rate to be perceived by investors as adequate compensation for risk, it should be the rate of return that they can realistically expect their investment to yield. As a result, the center point should be set at the most likely cost performance ratio. Then, if the final costs are at the expected levels, the center rate will be earned.

C. *One-time adjustment to the rate base*

In order to facilitate analysis and exposition of the subject, the discussion has up to this point been based on the premise that the incentive rate of return would apply to actual construction costs; that is, a varying rate of return would be used as the incentive mechanism.

The proposed rulemaking accomplishes an equivalent result by adjusting the rate base and allowing the operation phase rate on the adjusted rate base. The present value of the revenues provided by application of the operation phase rate to the adjusted rate base would equal the present value of the revenues provided by application of the allowed incentive rate of return to the actual rate base.[6]

The procedure for determining the one-time adjustment is: (1) Project the equity portion of depreciation and the after-tax return on equity over the life of the pipeline, based on the incentive rate and the conventional rate base; (2) calculate the present value of this stream of income, using the operating phase rate as the discount rate; and (3) replace the existing equity investment in the pipeline at the time of startup with this present value total.[7]

This one-time adjustment procedure does not change the present value of the project's revenue stream, as compared to the incentive rate of return. Because of this, the one-time adjustment methodology should yield the same result as varying the rate of return during operation.

The Commission, however, selects the one-time adjustment for two reasons. First, it will simplify future determinations of a just and reasonable rate of return for the pipeline. As financial conditions change over the next three or four decades, the rates of return allowed for all pipelines will vary. Under the one-time adjustment to the rate base herein adopted, the future determination of rates of return for the ANGTS can be made without having to consider the IROR mechanism or any penalties or premiums that were awarded for performance during the construction phase of the project. The one-time adjustment will continue to reflect those premiums, so that future rate of return determinations need only consider then-current conditions, not past events.

The second reason is that failure to adopt the one-time adjustment would

complicate future financing for expansions or loopings of the Alaskan gas project. Certainly the risks of participation in the project now are materially different from those to be associated with investments made years later on expansions of the system.[8] Without the one-time adjustment, a separate rate of return and a separate rate base would have to be established for an expansion or looping. Additionally performance in controlling costs in constructing the initial system should not prejudice additions to, or expansions of, that system.

III. SUMMARY AND EVALUATION OF COMMENTS ON THE MAY 8, 1978, NOTICE

One of the Commission's purposes in issuing this revised notice is to reduce the confusion surrounding the IROR concept which was apparently caused by the May 8 notice. To that end, the preceding section was intended to clarify the concept, design, and operation of an IROR mechanism.

This section specifically addresses many of the comments filed in response to the May 8 notice. All comments were carefully considered. Some contained valid criticisms and suggestions. The Commission incorporated these in its revised proposal.

A. *Applicability of the IROR*

1. *Proposals to completely abandon IROR.* Several of the comments on the proposed rulemaking of May 8, 1978, advocate outright abandonment of the entire IROR concept. The major arguments are (a) that the Commission is not legally required to employ IROR, and (b) that other, existing cost-control devices are adequate.

The second argument has been addressed in section I of this notice. As for the first argument, the legal requirement on the Commission to establish some type of incentive mechanism stems both from the Agreement on Principles with Canada (Agreement) and from the President's *Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision).*

The Agreement governs the two countries' plans to implement the joint project and was made a part of the President's *Decision.* The *Decision* gained the force of law when it was approved on November 2, 1977, by joint resolution of the Congress.[9]

Section 4(b) of the Agreement states:[10]

> * * * the return on the equity investment in the Pipeline will be based on a variable rate of return for each company owning a segment of the Pipeline, designed to provide inventives to avoid cost overruns and to minimize costs consistent with sound pipeline management.

The "Pipeline" referred to in this passage is defined in annex I to the agreement. It includes all segments of the project other than those in the lower 48 states. Thus, the agreement, through its inclusion in the *Decision* and its subsequent approval by Congress and by the Government of Canada, requires the application of some type of incentive system to the Alaskan and Canadian portions of the project.

In addition, the terms and conditions of the *Decision* (sec. 5) could be read as requiring the application of some type of incentive system to the entire project, as spelled out in the following passage:[11]

> If the direct capital cost estimates * * * for the overall project * * * materially and unreasonably exceed the comparable capital cost estimates filed by Alcan * * * on March 8, 1977, * * * the FPC may not issue a certificate for the project. If these final capital cost estimates are not excessive under the above standard, the FPC *may* use these final estimates for the U.S. segments as the basis for fixing a variable rate of return on equity that will reward the applicant for project completion under budgeted cost and penalize the applicant for project completion above budgeted cost. The variable rate of return shall be set to provide substantial incentives to construct the project without incurrent overruns. [Footnotes omitted.] [Emphasis added.]

Various comments argued that the term "may" in this section of the *Decision* gave the Commission flexibility in choosing whether to impose an inventive mechanism. Such an interpretation, however, is inconsistent with the entire theme and purpose of the President's *Decision.* The proper interpretation is that the Commission must fix an incentive system for the project but may use the final capital cost estimates filed with the

Commission prior to certification as the basis for that system. In other words, the *Decision* allows the Commission to select the basis for the mechanism, but requires that a mechanism be imposed. Further, since section 5 specifies terms and conditions for the entire project, we deem the Commission to be required by the *Decision* to assure that some type of incentive mechanism exists on all segments of the ANGTS.

The reason that the *Decision* requires imposition of an incentive mechanism to control costs is to protect the consumer and also to facilitate private financing of the project. The President in the *Report* left the implementation of such a mechanism to the Commission, with instructions "to balance the economic incentive with administrative feasibility."[12] While the President spoke in general terms of a variable rate of return, therefore, the Commission was at the same time given sufficient discretion in implementing the incentive mechanism to avoid a result which is not in the public interest. As discussed below in section IV. C, the Commission, after balancing economic incentive against administrative feasibility, believes that application of the IROR to the western leg segment of ANGTS is neither appropriate nor mandated.

2. Application to segments in the lower 48 States. A number of the comments argued that it is unnecessary to apply the IROR mechanism to segments of the ANGTS in the lower 48 states, because the potential for cost overruns on these segments is much less than in Alaska.

It has already been shown that the *Decision* requires the existence of some type of incentive system to the entire project. Even if it were not a legal requirement, however, it would be in the public interest to apply the IROR mechanism to the Alaskan and northern border segments of the ANGTS. The need for economic incentives throughout regulated industries was explained in the Introduction, and the need for such incentives to reduce costs on the lower 48 segments is just as real as on the Alaskan and Canadian portions of the project.

The difference between the Arctic segments and the conventional segments is in the degree of certainty in cost estimates. It is more difficult to predict Arctic construction costs than to predict the costs of conventional construction. Consequently, even though nonoverrun incentives may be the same, higher overruns may be incurred on the Arctic segments. It does not therefore follow, however, that cost-control incentives are not needed on the conventional construction segments. All of the reasons for applying some type of incentive system to the Arctic segments are equally valid for the conventional construction segments.

Some comments asserted that there are major practical problems in trying to apply an IROR mechanism to the western leg, because it will be part of existing operating systems and would not be project financed. Slightly different procedures would be needed for the western leg, but there appear to be no insurmountable problems in developing these procedures.[13] The commission has decided not to apply IROR as herein described to the western leg, however, because the net effect of doing so would be to increase costs to consumers. On the assumption that the financing plan for the Western Leg, which was presented to the President and made part of the report accompanying his *Decision*, is the one which is utilized, we believe that other, existing incentives to reduce construction costs are adequate for this segment of the system. (See sec. IV. C.)

Another problem mentioned in the comments is that parts of the lower 48 segments might be built in advance of the Alaska segment in order to carry Canadian gas.[14] Even so, we propose to apply the IROR mechanism to the northern border facilities. These facilities are part of the ANGTS, and thus application of some type of incentive mechanism is required by the *Decision*.

3. Designing different IROR schedules for different segments. Both the Office of Regulatory Analysis and the Office of Pipeline and Producer Regulation argued that different IROR schedules would be appropriate for each segment of the project. Their comments made two points:

(a) A major consideration in designing the IROR schedule is risk compensation. The investors must be adequately rewarded for bearing the risks of noncompletion, as well as the risks that severe overruns will lead to lower rates of return through the operation of the IROR. These

risks differ among the segments of the project, and the associated risk premiums awarded to investors should therefore correspond to the actual risks of each segment.

(b) The differences in the probable severity of cost overruns may imply that different incentives should be used for each segment: Where overruns are easy to avoid, a weaker incentive may be adequate.

Both these points argue for the design of separate IROR schedules for the different project segments. The Commission agrees with the first argument and will consider setting different values for the center rate and the center point for each segment to compensate for differences in risk. As to the second argument, however, the Commission at this time sees no reason to believe that the difficulty of searching out and implementing opportunities to reduce costs will vary between segments.

4. *Exempting certain equity funds from IROR.* The State of Alaska argued in its comments that the holders of convertible debentures would have no control over cost overruns, yet would be subject to the established incentive rate of return upon conversion of the debt to equity. Thus, certain investors could be penalized for behavior over which they claim to have no control.

It seems unlikely, however, that holders of convertible debt will have no control over costs. It will be in their interest to insure cost reduction, and the negotiation of their indenture agreement should allow them an opportunity to exert their influence over cost control procedures. Furthermore, the administrative problems involved in exempting certain equity funds from the incentive rate may be significant, especially if the operation phase rate is changed in the future.

B. *Effect of IROR on project financing*

1. *Project feasibility.* Alaskan Northwest, in its comments filed June 13, 1978, claims that the IROR mechanism will prevent private financing of the project. It then offers an alternative which it terms acceptable. The alternative, however, is identical in concept to the IROR mechanism contained in this draft revision. It cannot be the company's argument, therefore, that the general idea of IROR could prevent financing. Rather, it must be protesting the details and parameter values contained in the first notice.

The IROR schedule is designed so that investors will reject the project only if they anticipate overruns so high that the project would no longer be in the public interest.[15] At all lower levels of anticipated overruns, however, the allowed rate of return will be high enough to attract investors to the project.

In order to insure capital attraction, the Commission will build into the IROR schedule two important features:

(a) A risk premium to compensate investors for the special risks imposed by the IROR will be included in the center rate. This premium will be in addition to the compensation for the risks due to construction and operation. It will be designed to compensate investors for the fact that the IROR imposes variability on their possible returns.

(b) The IROR schedule will be designed so that rates of return below those of other investments will result only if cost overruns reach an unacceptably high level.[16] If potential investors reject the project because of the risk that the IROR mechanism will produce a low return, it will be because they place a higher probability on large cost overruns than does this Commission.

In addition to providing rates of return adequate to compensate for the risks of this project, the IROR will provide return rewards for controlling costs. This feature should be looked upon favorably by investors.

Prior to final certification, the sponsors will be required to show that they have obtained debt and equity capital sufficient to complete construction, even in the event of cost overruns. To secure such commitments, the capital suppliers will have to be convinced that the project is economically feasible and that adequate cost-control provisions have been made to limit cost overruns. To that end, an IROR plan will be supportive of the capital market's demand for cost-control assurance.

Commitments of capital should also be promoted by Commission actions designed to enhance the economic feasibility of the project. At an early stage of the

proceedings before the FPC, it was generally agreed that a cost-of-service tariff and rolled-in pricing would be required for this project, in order to provide assurance of revenues to capital suppliers. The Commission is therefore prepared to approve a cost-of service tariff (with some service interruption qualifications), to go into operation once gas flow commences. (The *Decision* prohibits any charges to customers prior to gas delivery.[17]) It is also probable that the cost of the gas will be rolled in with the cost of other gas available to the sponsoring companies.

2. *Effect on project debt.* Many of the comments pointed out that, in the event of overruns, a reduced equity rate of return would lower the coverage ratios for the project debt. This normally implies higher-cost debt financing or more difficulty in obtaining debt, since lower coverage tends to indicate higher probability of default.

On this project, however, the cost-of-service tariff will yield extremely dependable revenues, so that the probability of default will be very low regardless of equity and earnings coverage. The allowed revenues would always be more than sufficient for debt service, and would be so stable that the conventional interpretation of a thin coverage ration would not apply. Debt holders should not, therefore, react negatively to the IROR, and should be reassured by its tendency to reduce overruns, since overruns more than anything else threaten the project's viability. Reduced overruns also mean that debt holders will not be required to advance further funds to finance those overruns. In sum, it seems that on balance the IROR concept offers debt holders more benefits than risks.

Even though it seems highly unlikely that the IROR itself will prevent debt financing, some comments raised the possibility that the one-time adjustment to the rate base could hinder debt service. This concern was voiced by the financial advisers to the Alaskan Northwest partnership.[18] These advisers stated that debt financing would be unavailable if the rate base could be so much reduced that depreciation would be inadequate to cover senior debt principal repayment.

Even under the most extreme IROR mechanism imaginable, the reduction in rate base could not exceed the total equity investment in the project. Therefore, the depreciation component of the remaining rate base would always be adequate to repay the debt principal. Also, the rate of return on that rate base would always be more than adequate to cover interest on the debt.

A different problem might occur if the rate of debt repayment were much higher than the allowed rate of depreciation of the rate base. But this would constitute a problem of the timing of the cash flows, as opposed to a shortfall in the collection of the total sums required to service debt. Should this problem surface in the project's debt financing plan, the Commission will consider whatever adjustments are necessary to resolve it.[19] The problem should not arise, however. The sponsors and suppliers of debt should recognize the certainty of operating income which the cost-of-service tariff provides. This certainty should enable them to structure the debt repayments over a large period of the life of the project.

3. *Effect on project equity.* Many of the comments concerning the effect of IROR on equity have already been treated in the section entitled Project Feasibility. The ability of the project to attract equity funds is crucial. This section discusses some other specific issues of interest to equity holders.

a. *Risks due to IROR.* The principal effect of IROR on equity is to introduce some variability in the allowed return to equity, which implies that the equity investment is somewhat more risky. All funds invested in the equity portion of the project (25 percent of total) will receive the incentive rate of return determined from the IROR schedule which is ultimately adopted by the Commission. Since the allowed rate of return will vary according to cost control performance, the actual allowed rate of return cannot be determined in advance. Equity investors will have to form expectations about rate of return based on their expectations of the cost of the project.

These added risks due to the IROR are similar to ordinary business risks faced in competitive industries. In such industries, firms with lower costs are rewarded with higher profits, and equity investors must make judgments as to which firms will be most profitable. Imposing the

IROR on a regulated industry is merely an attempt to inject ordinary profitmaking incentives—and thus also some ordinary business risks—into a regulated industry. The risks associated with IROR should therefore not be unfamiliar to most investors.

b. *Marginal return on equity.* An issue which has generated considerable misunderstanding is the marginal return to equity investment in cost overruns. The effect of the marginal rate has been explained. The essential point is that *all* equity investment will be awarded the rate of return determined from the IROR schedule, and as overruns increase, that rate of return for *all* equity funds will decrease.

In the example IROR schedule contained in this notice, a cost overrun of 40 percent above the costs filed with the Commission in March 1977, after adjustments for inflation and design changes required by the Government, implies 16.4 percent return on equity for all equity invested, while a 30 percent overrun will be awarded a 17 percent rate of return on all equity invested. This unavoidably implies that those equity funds invested to provide for the overrun from 30 percent to 40 percent recieve only an 8 percent return. When this is "rolled in" with the return on the funds receiving 17 percent, however, the total result is a single pool of equity which covers the 40 percent overrun and which receives a 16.4 percent return.[20]

The marginal rate is important in determining the strength of the incentive to avoid overruns, but the compensation of equity investors is determined by the incentive rate of return on equity. which can be read directly from the IROR schedule.

c. *Double leverage.* The comments of Northwest Pipeline Corp. pointed out that the IROR could lead to violation of indenture agreements for companies with existing debt structures. The effect of any such restriction is subject to the control of the parent companies in their determination of the financing plan.

To the extent that part of the investment of project "equity" actually consists of parent corporation debt, varying the allowed return on project equity will affect the debt coverage of the parent. This could conceivably violate the indenture agreements of some of the parent corporations of the partnership. This seems unlikely, however, since the adoption of IROR materially increases the prospects that sponsor parent companies will not violate indenture debt limits, because the IROR reduces construction costs.

C. *Cost estimation and control*

Most of the comments filed included protestations that investors should not be penalized for cost overruns which are beyond the sponsors' control. In this connection, the comments argued that the list of changes in scope for which projected costs should be adjusted included in the May 8 notice was deficient. Because of the importance and complexity of this problem, the Commission has decided to consider the issue in a separate proceeding to be initiated as soon as possible.

An issue closely related to uncontrollable cost increases is that of inflation. Many of the comments dealt with methods of adjusting projected costs for the effects of inflation. These comments are discussed below, in the explanation of the Commission's new proposal on inflation adjustments.

The State of Alaska expressed concern that the IROR mechanism would prompt the project sponsors to reduce the quality of project construction in order to lower costs. The inferior construction would then have to be compensated for through higher operation and maintenance expenses. This strategy would hold down the cost performance ratio but would result in higher costs to consumers.

Although this strategy is a theoretical possibility, we believe that there is relatively little latitude at the current stage of project development to alter the pipeline design or construction methods to shift costs to the operating period. There are always tradeoffs in design such as that between additional compression (capital cost) and higher fuel cost (operating cost), but this Commission, the Federal inspector, and other Government agencies will closely monitor the pipeline design and construction to assure that the pipeline is built to the appropriate technical standards.

D. *Investment tax credit*

The Office of Regulatory Analysis argued that the investment tax credit

should be considered in determining the marginal rate in the IROR schedule. As the discussions of the marginal rate and the overall IROR schedule in later sections of this notice indicate, the Commission has not and will not consider the investment tax credit in determining the IROR schedule.

E. *Neutral zone in IROR schedule*

Many of the comments proposed a center zone, in which the rate of return would not decline. For example, for cost overruns between 0 percent and 40 percent, no penalty would be assessed, and a schedule might look like this:

Cost performance ratio:	*ROR* (Percent)
1.0	17.0
1.2	17.0
1.4	17.0
1.6	16.4

This proposal has the drawback that no cost-control incentives exist in the range 1.0 to 1.4. If the project were virtually complete at 1.2, then investment in overruns up to 1.4 would earn a marginal rate of 17 percent.

F. *Varying the marginal rate*

The Office of Regulatory Analysis suggested two reasons for choosing different marginal rates for different ranges of Cost Performance Ratios:

1. The difficulty of avoiding overruns may vary along the range of possible cost outcomes. ORA asserts that the strength of the incentive should vary accordingly: Where overruns are more difficult to avoid, greater rewards for cost control should be offered.

Although this argument has some theoretical appeal, the Commission cannot see any a priori reason to believe that cost overruns will be any easier to control at any stage of project completion. The Commission prefers to reserve the simplicity of a single marginal rate, set at a level that insures an incentive effect at all possible outcomes.

The Commission believes that much of the effort involved in containing cost overruns will be invested in planning prior to commencement of construction. A constant marginal rate will allow the project sponsors to establish policies for controlling overruns prior to construction which are commensurate with all of their financial constraints, including the incentive effect of the marginal rate, and retain those same policies throughout the construction period. Such constancy in and of itself should be helpful in controlling cost overruns.

2. This notice proposes to compensate investors for IROR risk by raising the level of the center rate of return as a result of adding the IROR risk premium. ORA suggests that compensation should instead be granted by increasing the possible rewards for cost underruns.

If the rewards for underruns were increased while the penalties for overruns remained the same, the expected return to investors would have increased. The value to investors of the higher potential rewards depends on the probability they attach to cost underruns. Designing the IROR schedule in this fashion requires the use of very low (even negative) marginal rates for low-cost performance ratios.

Gas consumers may prefer this method of compensating for investment risk, since it reduces their risk. The ORA alternative would result in a broader range of values for the incentive rate but would tend to reduce the range of values for the cost of service expected to be paid by consumers.

The major reservation about this alternative approach is that the increase in the incentive rate for lower values of the cost performance ratio may have to be very large in order to provide the same compensation for risk as would be provided by simply raising the center rate. If investors think underruns are unlikely, then they will attach little importance to the potential high rewards. Moreover, equity investors may be more concerned about the "downside potential" than about large possible gains. These two factors in combination could mean that extremely high rewards would have to be offered in order to match the effect of a small increase in the center rate.

G. *Accounting treatment of rate base adjustment*

In their comments, the Office of Pipeline and Producer Regulation and Tennessee Gas argued that the one-time adjustment introduced complex account-

ing and tax considerations into cost-of-service calculations.

We propose to consider the one-time adjustment to the rate base as an adjustment to the allowance for equity funds used during construction. Such procedures are already necessary in cost-of-service calculations without an IROR mechanism, since the allowance for equity funds used during construction must be recognized as a cost of the investment. The depreciation of equity AFUDC, however, is not utilized in calculating taxable income. Under current procedures, this is recognized in calculating corporate income taxes as a component of the cost of service.

Thus, the same procedures that are now used to account for the tax implications of the equity AFUDC account would be applicable to treatment of the one-time adjustment to the rate base. No new procedures will be needed.

H. *Alternative methods of applying IROR*

Many comments on the originally proposed rulemaking favored the application of the IROR schedule during the construction period only, in which case the one-time adjustment to the rate base would instead be accomplished through variation of the equity AFUDC rates of return.

This approach was considered by the Commission, since its incentive effect could be made comparable to the mechanism proposed in this notice. In order for the two approaches to be equivalent, however, the range of rates of return in the IROR schedule must be far greater for the AFUDC rate method than for the currently proposed method. This is because, under the AFUDC rate method, the incentive rate and return would be applied only during the construction period, rather than over the life of the project. Consequently, the total present value of any reward or penalty would be far smaller than if the same incentive rate were to be applied for the entire project life. These smaller rewards and penalties constitute a lesser incentive.

The degree of incentive effect of a given marginal rate can be properly evaluated only if it is derived from an IROR schedule that is in effect for the entire project life. The same IROR schedule applied to a shorter period yields smaller rewards or penalties and therefore a lesser incentive effect. For this reason, the Commission would consider the AFUDC rate method only if the range of rates in the IROR schedule were adjusted so as to invest the AFUDC method with an incentive effect equivalent to that attained by the life-of-project method used in this notice.

The Commission's adjustment to rate base methodology also allows clearer recognition of the changed degree of risk associated with the project after gas deliveries commence. By using a rate-base adjustment to compensate for all construction phase risks and insisting on an operation phase rate appropriate for the risks encountered at that time, the Commission is trying to assure that those who bear the construction phase risks have the opportunity to earn a significantly higher rate of return than those who do not. The Commission's preferred method is consistent with the policy objective we were seeking in approving the discounting principle which is part of the sponsoring companies' Partnership Agreement.

I. *Effect on consumers*

Some parties pointed out that IROR entails some costs to consumers. Investors must be allowed higher rates of return as compensation for the risks added by the IROR. In addition, any benefits from cost control must be shared with investors, in the form of the higher incentive returns paid as rewards for good management.

The Commission must structure the IROR mechanism in such a way that the benefits to consumers from cost control outweigh the costs imposed on consumers by IROR. The example IROR schedule presented in this notice is designed to provide consumers with net benefits under very plausible conditions. (See sec. IV.A.5.)

J. *Alternative proposal of Alaskan Northwest*

In its comments, the Alaskan Northwest partnership proposed an alternative IROR mechanism which in many respects is similar to an alternative the Commission discussed in the notice of May 8. The major features of the Alaskan Northwest alternative are:

(1) Only the rate of return on equity during construction (the AFUDC rate) would be increased or reduced by cost control performance.

(2) The incentive rate of return would have a high rate of 20 percent and a low rate of 12 percent. The center rate in the proposed schedule is 17 percent.

(3) In the center of the IROR schedule would be a "neutral" area where the rate of return would not be changed. In the example given by Alaskan Northwest, the neutral area extended from a cost performance ratio of 1.01 to 1.40. In other words, if cost overruns were less than 40 percent over the projected costs, the incentive rate would equal the center rate of 17 percent.

(4) During construction, projected costs would be revised to reflect all changes in prices of materials and labor, changes in design, route, or schedule ordered by Federal or State authorities, force majeure or acts of God, and all other changes in cost beyond the control of the sponsors. Only changes in quantities of materials and labor would be tabulated in cost overrun.

We have constructed an example of how the Alaskan Northwest IROR mechanism would be applied to various cost overruns within the Alaskan segment of the system. The values used in the alternative mechanism are taken from the comments of Alaskan Northwest, while the construction costs, schedule, and financial assumptions are taken from earlier filings and applications, in particular the March 1977 capital cost estimates.

Table I presents an example of the Alaskan Northwest proposal. For comparison,we also show an example of the cost of service under conventional ratemaking—i.e., without an IROR mechanism—for various levels of cost overruns. The costs of service for various levels of the cost performance ratio are calculated by simply increasing all direct capital costs in the March 1977 estimate by the proportion indicated in the cost performance ratio.[21]

The cost of service calculations in 1975 dollars follow the methodology used in the President's *Decision and Report*.[22] In order to measure the cost of service over the life of the project, the present worth average cost of service for a 20-year operation life has been calculated. This average is higher than a simple arithmetic average, but it more accurately reflects the change in cost of service over time.[23]

TABLE I

CONVENTIONAL RATE MAKING 17% AFUDC & Operating Rate				ALASKAN NORTHWEST PROPOSAL Variable AFUDC Rate & 17% Operating Rate			
Cost Performance Ratio	Rate Base ($ Million)	Present Value Average Cost of Service ($/MCF)	AFUDC Rate (%)	Rate Base ($ Million)	Change in Rate Base ($ Million)	Present Value Average Cost of Service ($/MCF)	Equivalent Operating Rate on Equity (%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
0.8	2,769	0.332	20.0	2,804	35	0.339	17.8
1.0	3,461	0.407	18.0	3,476	15	0.410	17.3
1.2	4,154	0.483	17.0	4,154	0	0.483	17.0
1.3	4,500	0.521	17.0	4,500	0	0.521	17.0
1.4	4,846	0.558	17.0	4,846	0	0.558	17.0
1.6	5,538	0.634	13.0	5,450	−89	0.615	15.9
1.8	6,230	0.709	12.0	6,107	−124	0.684	15.7
2.0	6,922	0.785	12.0	6,785	−138	0.755	15.7
2.2	7,615	0.860	12.0	7,464	−151	0.829	15.7
2.4	8,307	0.936	12.0	8,142	−165	0.902	15.7

NOTES FOR TABLE I

Column (2)—Calculated from the March 1977 cost estimates for the Alaska segment in 1975 prices assuming 75 percent debt capitalization, 10 percent interest rate on debt, 17 percent rate of return on equity, and the proportional change in all direct capital costs indicated by column (1).

Column (3)—Assumes 5 percent annual inflation in capital and operating costs, with the subsequent annual cost of service deflated to 1975 prices using 5 percent deflation factor. Gas fuel cost is $1.60 per MCF. Rate of interest on debt is 10 percent. Rate of return on equity is 17 percent. Present value average cost of service is

calculated from the formula:

$$\sum_{t=1}^{20} C_t(1.1)^{-t} \Big/ \sum_{t=1}^{20} (1.1)^{-t}$$

where C_t is annual unit cost of service in 1975 prices.

Column (4)—Taken from p. 16 of the initial comments by Alaskan Northwest Transportation Company.
Column (5)—Same as column (2), except that the AFUDC equity rate is that given in column (4).
Column (6)—Column (5) minus column (2).
Column (7)—Same as column (3).
Column (8)—Rate of return on equity during construction applied to the rate base in column (2) that generates the same present worth at a 10 percent discount rate of the return of equity and after-tax return to equity as does the 17 percent rate of return applied to the rate base in column (5).

A basic feature of the Alaskan Northwest proposal is that the equity rate of return would vary only during construction. The Commission has calculated the equivalent change in the equity rate during operation. By equivalent, the Commission means the operation phase rate applied to the conventional rate base which would produce the same present worth of cash flow to equity investors as would the 17 percent operating rate applied to the rate base derived from the variable AFUDC equity rate.[34] To use an example from table I, with a cost performance ratio of 2.0 equity investors should be indifferent between receiving an operation phase rate of return of 17 percent on the rate base of $7.46 billion or receiving a rate of 15.7 percent on a rate base of $7.62 billion. The rate base of $7.62 billion is the conventional rate base derived from an equity AFUDC rate of 17 percent, while the rate base of $7.46 billion is derived from the equity AFUDC rate lowered to 12 percent because of the assumed large cost overruns.

The Commission's fundamental objection to the Alaskan Northwest proposal is that the implicit marginal rate of return is not less than the rates of return that can be earned on alternatives of equal risk, and thus does not provide sufficient incentive for management to reduce costs. This is obviously the case with the so-called "neutral zone," for values of the cost performance ratio between 1.01 and 1.40, there would be no reduction in the AFUDC equity rate. In this zone, the IROR schedule is flat: the marginal rate is equal to the incentive rate.[35] On all cost overruns within this zone, therefore, sponsors could expect to earn the after-tax rate of return of 17 percent.

Even outside the neutral zone, the marginal rate of return over the operating period would be very high. In table I, the equivalent operating rates of return vary from 17.8 percent for a cost performance ratio of 0.8 to 15.7 percent for a cost performance ratio of 2.2. The marginal rate that would produce this drop in the incentive rate is 14.5 percent.[36] On the average, equity investors could expect the rate of return on their investments in cost overruns to be 14.5 percent: a rate of return high by previous standards of this Commission and higher than one could expect in many other equity investments in the United States. Therefore, this proposed IROR schedule, if applied to the construction phase only, would not offer sufficient incentive to control costs.

A second concern with this proposal involves the relationship among the overall level of allowed rates, the degree of penalty for overruns, and the degree to which projected costs may be revised during the course of construction. The comments of Alaskan Northwest and other project sponsors suggest that they envision a process by which projected costs are continually revised to account for changes to the earlier cost estimates caused by design or routing modifications required by government authorities, force majeure, acts of God, strikes, and changes in prices of labor or materials. While adjustments for some of these events will undoubtedly be required, it is unlikely that the cost performance ratio would ever exceed 1.0 if all of these changes in the projected cost estimates were made. If this Commission were to accept a policy of unlimited adjustments to the sponsors' cost estimates, it would feel compelled to require a lower marginal rate and a lower overall level of rates (a lower center rate of return). The applicant has, however, proposed a very high marginal rate and a center rate of 17 percent, which is substantially and un-

necessarily higher than the range of rates allowed by this Commission in the past.

IV. THE COMMISSION'S REVISED PROPOSAL

Using the principles outlined in section II, the Commission has revised the terms and conditions first presented in its May 8 proposal of rulemaking. Included in this section is an example of an IROR schedule. The values in that example are representative of numbers the Commission could approve upon appropriate findings in an evidentiary proceeding. The example is reasonable, given the estimates of the underlying rates of return and risk premiums specified in this section. The actual rates of return will of course be set when the various components of the overall risk distribution framework, such as the scope change process, the capital structure, and the workings of the project company tariff, have been specified and when evidence on the rates of return and risk premiums has been considered by the Commission.

A. *An example IROR schedule*

1. *Benchmark rates of return.* a. *The operation phase rate.* The operation phase rate is the rate of return on equity that will be allowed after the pipeline is in operation and after the one-time adjustment to the rate base has been made. This rate will be set pursuant to the usual process for determining allowable rates for pipelines with similar operating risks.

The degree of the pipeline's operating risk exposure is a point in controversy. Several comments argued that the risk exposure would be substantial. On the other hand, the Office of Regulatory Analysis argues that ANGTS operating risks will be much lower than those of other pipelines, since there will be no risk associated with decline in throughput.

It is true that the cost-of-service tariff eliminates the risk of variations in throughput which are beyond the control of the pipeline by automatically adjusting the transportation tariff accordingly. For certain other service interruptions, however, the cost-of-service tariff will have provisions for lowering rates of return. Service interruptions pose a risk of unknown dimensions, inasmuch as these pipelines will traverse a hostile environment and will have unknown operating conditions. The details of the project company tariff will determine the degree of risk being borne by the sponsoring companies. The dimensions of the pipeline's risk exposure will be an important issue to be resolved in the evidentiary proceedings which will be held.

For present purposes, a rate of return of 13 percent has been chosen as the operation phase rate in the numerical examples to be presented later. The Commission has set rates of return on equity for two pipelines with cost-of-service tariffs: Pacific Gas Transmission (13.0 percent) and Columbia Gulf Transmission (13.5 percent).[27]

The final rate will be determined after more information about risks during the operation phase has been specified in the project company tariff and may vary between segments of the ANGTS. Over time, this rate will then be adjusted up or down as general financial conditions change.

b. *The nonincentive rate.* The nonincentive rate of return on equity is the rate that would be allowed if the IROR mechanism were not employed. This rate should provide equity investors with a risk premium for the construction phase risks associated with the Alaskan gas project, but should not provide any compensation for the particular risks created by an IROR mechanism.

Fifteen percent has been chosen as an example rate of return on the Alaska segment, for the following reasons:

Fifteen percent is at the lower end of the range discussed by the applicants in the administrative hearings on this case.[28]

Fifteen percent was found reasonable by the administrative law judge who heard the case before the FPC.[29]

Fifteen percent was used in cost-of-service calculations in the FPC's report to the President and in the President's *Decision*.[30]

The difference between the 13 percent operation phase rate and the 15 percent nonincentive rate is intended to compensate for the construction phase risks associated with the Alaskan gas project.

The rate for the Northern Border segment may be somewhat less than the rate for the Alaska segment, since it will be built in a more familiar environment and does not involve as much uncertainty

as the Alaskan segment. Because it is part of a large, complex system and because its success is dependent on successful completion of other segments, however, it may still present more risk than conventional lower 48 pipelines.

c. *The center rate.* The center rate of return on equity is the rate specified by the IROR schedule when actual construction cost equals the expected level of cost overruns: i.e., the rate which is the center point of the schedule. Because of the uncertainty about the ultimate rate of return created by the IROR mechanism, this center rate must have a premium over the rate that would be allowed if no IROR mechanism were used.

Seventeen percent is used in this example as the center rate for the Alaska segment. The 2 percentage point difference between the nonincentive rate and the center rate represents compensation for the risks created by the IROR mechanism.

Since there is less uncertainty about construction costs for the more conventional pipeline construction on the Northern Border system, the compensation for the risks of the IROR mechanism may be less on that segment. This implies a smaller difference between the center rate and the nonincentive rate. Again, more definitive information in the complete structure of allocation of project risks must be available before the Commission can make a final determination of this rate.

2. *The marginal rate.* In determining a marginal rate of return that will embody a significant incentive to control costs, the Commission must compare the marginal rate to the cost of the capital that sponsors invest in the equity portion of the project. A marginal return below the cost of that capital will discourage sponsors from investing in overruns.

The sponsors' cost of capital will be determined by their own costs of equity and debt, as well as by the composition of the capital they invest in the equity portion of the project. If sponsors were to invest only equity, then an effective marginal rate would only need to be lower than the cost of equity. If the sponsors raise their capital for the equity portion of the project through some combination of debt and equity, however, then the marginal rate must be set below the weighted average cost of that capital. If the sponsors were to finance this investment completely through the sale of debt, then the marginal rate would have to be less than the after-tax cost of debt.

The potential investors for the equity portion of the project are diversified corporations that invest in other U.S. industries. This suggests that their costs of equity are near some average of the returns on equity available in all U.S. industries. This number is, of course, not directly observable in the marketplace, since part of the return is appreciation in stock market prices. Studies of historic earned rates of return show that the long-run rate of return on common stock (dividends plus capital gain) ranges from 9 to 11 percent.[31] Adjusted for the 85 percent exclusion rule for intercorporate dividends, this would suggest a return of 8 to 10 percent. In light of current expectations that future inflation will be higher than the average over past decades, these rates of return could be increased by perhaps 3 percentage points, to 11 to 13 percent.

The current market rate on long-term debt is near 10 percent, implying an after-tax cost of debt of roughly 5 percent. Assuming that investments in the project equity are financed at a typical debt ratio of .60, these rough estimates of capital costs can be used in calculating an example of an effective marginal rate. The weighted average cost of capital implied by the assumptions is: (.4)(13)+(.6)(5)=8.2.

Based on this calculation, an 8 percent marginal rate is embodied in the example IROR schedule.

3. *The center point.* The center point of the IROR schedule is that cost performance ratio associated with the center rate of return. The center point should represent the expected level of costs after adjustments for inflation and design changes. If the final cost estimates do not differ significantly from the March 1977 estimates, a center point for the Alaska segment might be 1.3, as used in the example. The center point on the Northern Border segment may be lower.[32] If the project sponsors prefer significant freedom to revise cost estimates for reasons other than inflation, it seems likely that the recommended center points should be lower.

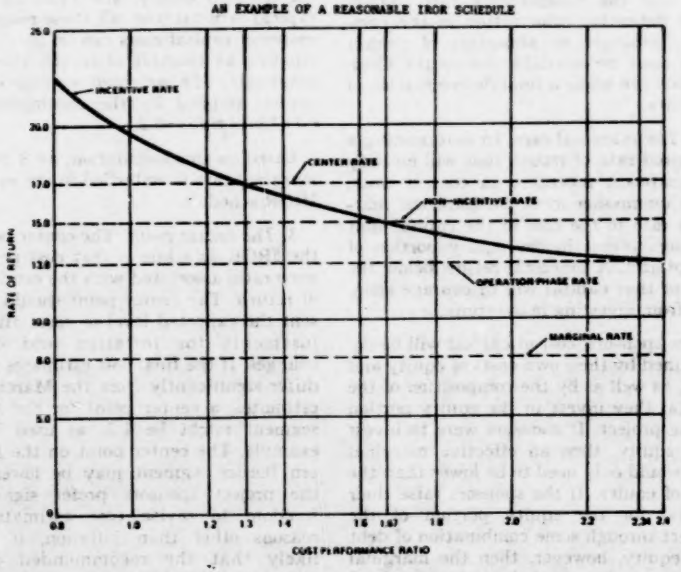
4. *The example schedule.*—Having estimated values for the center rate, the marginal rate, and the center point, an entire IROR schedule can be determined. The example resulting from a center rate of 17 percent, a marginal rate of 8 percent, and a center point of 1.3 is shown below.[33]

8 pct Marginal Rate
17 pct Center Rate
1.3 Center Point

Performance ratio:	*ROR (Percent)*
.8	22.6
1.0	19.7
1.2	17.8
1.3	17.0
1.4	16.4
1.6	15.3
1.8	14.5
2.0	13.9
2.2	13.3
2.4	12.9

Pursuant to this schedule, a rate of return of 19.7 percent would be allowed for the Alaskan segment if actual costs after correction for inflation and changes in scope were no higher than the March 1977 estimates (a cost performance ratio of 1.0). For a 30 percent overrun (a cost performance of 1.3), a rate of 17 percent would be allowed. At a 67 percent overrun from the corrected March 1977 estimates, the rate would be reduced to 15 percent (the nonincentive rate). In other words, only a constant dollar cost increase equal to two-thirds of the original estimate would lower the rate of return in this example below the rate that would be allowed if no IROR mechanism had been adopted. At a 134 percent overrun—i.e., a cost performance ratio of 2.34—the rate of return would be reduced to 13 percent (the operation phase rate). In other words, only for more than a doubling of construction costs' would the rate of return in this example be reduced below what is being allowed for other pipelines.[34]

AN EXAMPLE OF A REASONABLE IROR SCHEDULE



This example of the Commission's revised proposal is displayed in table II, which shows the incentive rate for various levels of the cost performance ratio, the size of the one-time adjustment to the rate base, and the adjusted rate base. It also gives the present value average cost of service.

5. *Benefit to consumers.* As discussed earlier, the IROR mechanism may result in higher rates of return allowed on equity, which will increase costs to consumers. However, the IROR mechanism will create an incentive for management to reduce construction costs, thus benefiting consumers. On balance, the Commission believes that the benefit of lower construction costs will outweigh the possibly higher rate of return to equity attributable to the IROR mechanism.

In the situation where cost overruns exceed 60 percent of the originally estimated costs, column (4) of table II[35] shows that the IROR will be less than would probably be allowed by more typical ratemaking procedures. Consumers thus would clearly benefit from the IROR in this situation.[36]

If cost overruns are less than 60 percent, the incentive rate of return will be higher than would conventionally be allowed. However, the incentive effect of the IROR should result in lower construction costs than would be the case without the IROR. If cost reductions are reasonable, consumers will realize a net benefit.

Column (9) of table II shows for each cost performance ratio the minimum reduction in construction costs necessary for consumers to realize a net benefit. For a cost performance ratio of 1.3 (the level expected in the President's *Decision*), a reduction in construction costs of only 6 percent below what those costs would have been without the IROR will offset the higher rate or return. For a lower cost performance ratio of 1.0, the necessary reduction in construction costs is about 14 percent below what those costs would have been without the IROR. The IROR is expected to reduce construction costs by at least these amounts; consequently, consumers should, on balance, benefit from the IROR mechanism.

B. *Inflation adjustment*

The initial proposal recognized that the sponsors should not be held responsible for increases in costs that resulted from general inflation in the economy. The initial rulemaking proposed to divide the final cost estimate into a number of categories for which cost or price indexes were available. These indexes would then be used to inflate the projected costs and thus increase the projected rate base to account for inflation.

This approach has a major weakness. If the pipeline experienced major construction delays resulting in costs incurred after the period anticipated in the applicant's final cost and schedule estimates, this approach would provide no protection against inflation during the schedule extension, since no projected costs were anticipated for this period. Suppose for example that the applicant had projected a 5-year construction period, but because of delays during construction substantial expenditures projected for the 5th year were actually incurred in the 6th year. Suppose, too, that because of high rates of inflation these expenditures are much higher than had they been incurred during the 5th year. Since the projected costs show no expenditures during the 6th year, there is no adjustment for inflation during the 6th year.

TABLE II

CONVENTIONAL RATE MAKING 15% AFUDC & Operating Rate			FERC PROPOSAL 15% AFUDC Rate, 13.00 Operating Phase Rate, Adjusted Rate Base					
Cost Performance Ratio	Rate Base ($ Million)	Present Value Average Cost of Service ($/MCF)	Incentive Rate (%)	Adjustment to Rate Base ($ Million)	Adjusted Rate Base ($ Million)	Present Value Average Cost of Service ($/MCF)	Equivalent AFUDC Rate (%)	Consumer Break even Cost Reduction (%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
0.8	2,747	0.310	22.6	469	3,216	0.377	47.5	21.6
1.0	3,433	0.380	19.7	408	3,041	0.432	39.2	13.7
1.2	4,120	0.450	17.8	346	4,466	0.487	33.0	8.2
1.3	4,463	0.485	17.0	316	4,779	0.514	30.5	6.0
1.4	4,807	0.520	16.4	285	5,092	0.542	28.2	4.2
1.6	5,493	0.590	15.3	224	5,717	0.596	24.3	1.0
1.8	6,180	0.660	14.5	162	6,342	0.651	21.2	− 1.4
2.0	6,867	0.731	13.9	101	6,968	0.700	18.5	− 3.4
2.2	7,553	0.801	13.3	41	7,594	0.761	16.3	− 5.0
2.4	8,240	0.871	12.9	− 22	8,218	0.816	14.3	− 6.3

NOTES FOR TABLE II

Column (2)—Same as column (2) in table I except that the AFUDC equity rate is 15 percent.

Column (3)—Same as column (3) in table I except that the equity rate of return during operation is 15 percent and the rate base is given in column (2).

Column (4)—Calculated from the formula:

$$\frac{(17.0)(1.3) + 8.0[\text{Col. } 1 - 1.3]}{\text{Col. } 1}$$

For example, at a cost performance ratio of 2.2:

$$\frac{(17.0)(1.3) + 8.0[2.2 - 1.3]}{2.2}$$

$$= 13.3$$

where the marginal rate of return is 8 percent and the Center Rate is 17 percent, at a Cost Performance Ratio of 1.3.

Column (5)—Present value (at 13.0 percent discount rate) of the return of equity and after-tax return to equity at the operating equity rate of return given in Column (4) minus the equity investment in the rate base given in Column (2).

Column (6)—Column (5) plus column (2).

NOTES FOR TABLE II CONT.

Column (7)—Same as column (3) in table I except that the rate of return on equity during operation is 13.0 percent and the rate base is given in column (6).

Column (8)—The AFUDC equity rate that would produce the rate base in column (6).

Column (9)—Calculated from the formula:

$$\frac{\text{column (7)} - \text{column (3)}}{\text{column (3)}}$$

The revised approach is to divide the actual construction costs into cost categories for which price or cost indexes are available. These indexes will be used to deflate actual costs to base-year costs. The adjustment for inflation will thereby also apply to costs that occur beyond the projected period of construction. This rate base adjusted for inflation will be termed the deflated actual rate base in 1978 dollars (or whatever year is the base year for making cost estimates). The deflated actual rate base in 1978 dollars will be divided by the projected rate base (in 1978 dollars) to determine the cost performance ratio and thus the incentive rate of return.

A number of comments on the initial proposal emphasized the need to choose price indexes that reflect the inflation experienced in pipeline construction in the

specific geographic areas where the pipelines will be built. The Commission fully recognizes the problem mentioned in many comments that no price index perfectly measures the inflation experienced by any individual or any project. For example, the widely used consumer price index is only an approximation of the inflation experienced by any particular consumer.[37] The same problem will exist for each cost category in the Alaskan gas project. However, the Commission believes that existing, widely accepted indexes do not bias the measure of inflation in any particular direction. Certainly for some categories of costs the price indexes may overestimate the actual rate of inflation.

The Alaskan Northwest partnership requests that the inflation rate for Alaska be used instead of the national inflation rate, because the costs in Alaska are higher. Construction costs are assuredly higher in Alaska. (The construction of the oil pipeline in Alaska provides considerable information on the premiums that must be paid for Alaskan labor or materials and supplies used in Alaska. The cost estimates submitted by the sponsors recognized these premiums.) But it does not necessarily follow that the rate of change in costs (the inflation rate) in Alaska will be either higher than or lower than the rest of the nation. Considering the advantages of using the national rate, and in the absence of clear evidence that the regional rate will differ significantly from the national rate, the Commission would plan to use the national rate of inflation.

The Alaskan Northwest partnership also suggests that the cost of each unit of labor or materials is also beyond its control. It argues that only the quantities of labor and materials should be considered controllable. The Commission agrees that changes in prices or unit costs caused by general inflation are beyond the sponsor's control and will accordingly adjust such costs for inflation by use of cost or price indexes. However, the size of the enterprise relative to the Alaskan economy and the natural gas pipeline industry would indicate that the sponsors should have a major ability to influence wages and prices and should be given an incentive to do so. The labor costs, for example, will probably be the result of negotiations between the sponsors or their contractors and labor unions. As the quantity of labor required will be very large, we believe the project sponsors will have some ability to influence the price they pay.

It is not the Commission's intention to penalize the project sponsors for the effects of inflation; rather, it is the Commission's intention to hold them harmless for cost increases due to general inflation. The Commission's concern with the sponsors' approach is their implicit assumption that they are powerless to affect the prices they pay.

C. *Application to the western leg*

Pacific Gas Transmission (PGT) and Pacific Interstate Transmission state that difficulties would be encountered in determining the size of the one-term adjustment to the rate base for the western leg segment of the ANGTS. They argue that problems are created because the western leg will be an expansion of an existing system and will be owned and operated by a corporation with an existing financial structure.

A slightly different procedure would be needed for the western leg than is used for the project-financed northwest border and Alaska segments. The attached terms and conditions state that the return of equity and after-tax return on equity over the life of the system will be estimated based on a financing and capitalization plan approved by the Commission. For the western leg, it might be possible for the Commission to use a financing and capitalization plan that is representative of the overall financial structure of the company owning the western leg.

The comments also argued that further complications would be created by the possibility of the early construction of a portion of the western leg and northern border segments to carry Canadian gas as part of an "advance delivery" of Alaska gas. The only complication we see resulting from applying the IROR mechanism to the facilities needed to transport Canadian gas is that the depreciation rate for the pipeline may be relatively high, reflecting the shorter period of the contract for Canadian gas. This simply means that the projection of the return of equity and the after tax return to equity used to calculate the one-time adjustment to the rate base would be based on a relatively high rate of depreciation reflecting the

reliatively short period for which gas reserves would be dedicated to the pipeline at the time of authorization of these facilities.

The consideration which persuades us not to apply the IROR to the western leg is cost to consumers. The looping of an existing pipeline along an existing right-of-way to transport an assured supply of gas is an undertaking of conventional risk, particularly considering the assurance of adequate revenues provided by a cost-of-service tariff. Because of this conventional risk, the financing plan presented to the President and included in the *Decision*[38] called for 100 percent recourse debt financing for this segment. As distinct from project financing wherein the project itself must provide assurance of debt service, the debt to be used for the western leg is to be issued by the sponsoring companies, Pacific Gas Transmission for the Washington and Oregon segments and Pacific Gas & Electric for the Northern California segment, and guaranteed by the parents. This type of financing is much lower in cost than the mixture of debt and equity which will be used to finance the other segments of the project.

Use of the IROR mechanism on the western leg would undoubtedly increase financing costs. Debt costs would likely increase because of the additional risk, but more importantly the debt/equity ratio would likely decrease. The use of 100 percent debt financing will increase the proportion of debt in the total capitalization of the sponsoring companies to high levels. This is particularly true for Pacific Gas Transmission. The additional risk created by the IROR may make such high levels of debt capitalization impractical and thus require some equity financing for the western leg. Particularly in view of the tax consequences of additional equity financing, the Commission believes the additional financing costs associated with imposition of the IROR mechanism on the western leg would more than offset the benefits of reduced construction costs which might be expected to be achieved.

The Commission also believes that cost control incentives are already present in the use of 100 percent debt financing. An incentive effect occurs on equity benefits of cost overruns. Also, the impact of that debt on the parent companies' financial conditions—debt guarantee capacity and overall credit rating—will cause them to insist on stringent construction cost-control measures for the western leg. Although not as focused as the IROR mechanism, the Commission believes this incentive will be adequate to insure proper control of construction costs for the western leg.

Having found that the present western leg financing plan already includes a sufficient incentive mechanism, we also note that imposition of IROR to the western leg would be administratively infeasible, not in the sense of ease of application, supra, but in terms of impact on the consumer. The 100 percent recourse debt financing of the western leg should result in a lower cost of service (due to higher bond rating and lower cost of recourse debt and favorable tax consequence of debt financing) without IROR than with it.

In the Commission's considered judgment, the application of IROR to the western leg lacks the salutary regulatory effect which it will have on the other segments of the project. There is already adequate incentive to control construction costs, and the two bases underlying the President's variable rate of return condition have already been satisfied: the consumer is better off under the existing western leg financing plan, and the recourse nature of the debt acts to assure private financing.

V. RELATION OF THIS RULEMAKING TO THE CHANGE-OF-SCOPE PROCEEDING

Throughout this notice, reference has been made to the relationship of the values of an IROR schedule to the outcome of the separate change-of-scope proceeding. That interdependence should be emphasized, for even though the change-of-scope question has been spun off to a separate proceeding, the resolution of the question will be a major determinant in the selection of the final values used in the IROR schedule.

The greater the flexibility that is allowed in adjusting for scope changes, the less is the risk of cost overruns borne by the project sponsors. The actual values in the IROR schedule are partly determined by the risk of cost overruns, and anything that changes the amount of that risk will change the proper compensation

for risk to be allowed in the IROR schedule.

Greater flexibility in adjusting costs also reduces the incentives to control costs. The final treatment of scope changes will also affect the Commission's choice of a marginal rate.

The illustrative values in the IROR schedule were based on the March 1977 cost estimates. Revisions in these cost estimates, other than for inflation and scope changes required by the Government, also will affect the final selection of values in the IROR schedule.

The proper values for the different types of rates and ratios (of which estimates have been provided in this notice) must be determined through an evidentiary proceeding to be conducted when all elements of the risk allocation framework have been put in place. We expect that the project sponsors are eager to have this process completed. It is our intention that these matters be resolved as expeditiously as possible.

VI. WRITTEN COMMENT PROCEDURES

The Commission invites interested persons to submit written comments with data, views, and other information concerning the matters set forth in this notice. An original and 14 copies should be filed with the Secretary of the Commission by October 6, 1978. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM78-12.

All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

In consideration of the foregoing, the Commission proposes that the following terms and conditions be attached to the certificates of public convenience and necessity to be issued by the Commission for the Alaska Natural Gas Transportation System, as set forth below.

By the Commission.

KENNETH F. PLUMB,
Secretary.

TERMS AND CONDITIONS

(1) *Applicability.* The incentive rate of return (IROR) rule will apply to two of the three segments of the Alaskan Natural Gas Transportation System within the United States as defined in the President's *Decision and Report to Congress on the Alaska Natural Gas Transportation System* (referred to hereafter as the *Decision*). These segments are: (1) The portion of the system within the State of Alaska, and (2) the portion of the system from the United States/Canadian border near Monchy in the Province of Saskatchewan to a point near Dwight in the State of Illinois. In the following terms and conditions, the term pipeline refers to each of these two segments, and the terms and conditions apply to each. The values for schedules, parameters, or variables to be established by the Commission in order to implement the IROR rule pursuant to some future evidentiary proceeding may be different for each of the segments.

(2) *Cost performance ratio.* Pursuant to the second finance term and condition of the *Decision* (p. 36), the rate of return on equity during the operating period of the pipeline will be increased if the pipeline is completed under budgeted cost and reduced if the pipeline is completed over budgeted cost. The relationship between budgeted cost and completed cost will be determined by a cost performance ratio. This is ratio of the deflated actual rate base (see condition 4 below) to the projected rate base (see condition 5 below).

(3) *Incentive rate of return schedule.* The Commission will establish an IROR schedule which may be in the form of a table or formula. The IROR schedule will specify a value for the IROR for each value of the cost performance ratio. The IROR schedule will compensate equity investors for the degree of construction cost overrun and schedule delay risk which they bear. The IROR schedule will take into account financing plans, depreciation schedules, and any other factors which the Commission determines to be relevant and important.

(4) *Deflated actual rate base.* The deflated actual rate base will be determined at the start of operations from direct capital or construction costs after conversion into base year prices (see condition 8 below) actually incurred in the construc-

tion of the pipeline. The deflated actual rate base will include only those direct capital costs which the Commission finds to be prudently incurred. An allowance for funds used during construction (AFUDC) will be included. The AFUDC will be based on the direct capital costs in the base year prices, the actual interest rates paid on debt during construction, and the nonincentive rate of return on equity defined below in condition 10.

(5) *Projected rate base.* The projected rate base will be calculated at the start of operations from the final cost and schedule estimate submitted to and approved by the Commission pursuant to condition 6 below after adjustment for changes in scope pursuant to condition 9 below. An AFUDC will be included and will be calculated from the final cost and schedule estimate, the actual interest rates experienced during construction, and amounts of debt and equity that would have been outstanding if the expenditures for construction as projected in the final cost and schedule estimate had actually occurred, and the nonincentive rate of return on equity defined below in condition 10.

(6) *Final cost and schedule estimate.* Pursuant to the second finance condition in the *Decision,* the applicant for a certificate of public convenience and necessity for the pipeline shall submit to the Commission a final cost and schedule estimate in 1975 prices, adjusted to reflect any design changes resulting from the agreement on principles with Canada and any addendum thereto, for comparison with the capital cost estimates filed by Alcan with the Federal Power Commission on March 8, 1977. This final cost and schedule estimate must also be submitted in 1978 or later base-year prices and with costs set forth according to formats to be specified by the Commission. (See condition 7.) The March 1977 cost estimate referred to in the second finance term and condition in the *Decision* must also be resubmitted in the same format for comparability with the final cost estimate. An explanation of any significant differences between the March 1977 and the final cost and schedule estimate must be provided. The date of the base-year period for submitting costs may be determined by the applicant.

(7) *Cost estimate format.* All cost estimates shall be submitted to the Commission according to specifications to be determined by the Commission. Prior to submittal of the final cost and schedule estimate, the applicant may submit a proposal for the cost estimate format to the Commission. The cost estimate format will specify the functional categories or components into which the total cost estimate must be divided and the key parameters or assumptions for which values must be provided. Each functional category of cost must be further divided according to the time period in which the costs are estimated to occur. The breakdown of costs shall be in sufficient detail that the Commission may compare the various cost estimates and determine the reasonableness of any changes.

(8) *Adjustment of actual construction costs for inflation.* Actual costs of construction found to be prudently incurred by the Commission will be divided into a number of cost categories and further divided into periods of time when the costs were incurred. For each cost category, the Commission will specify a price or cost index that will be used to measure the inflation experience for commodities or services in that category. The actual costs of construction in each cost category and in each time period will be divided by the ratio of the value of the price index for that category and for that period of time by the value of the index in the base year. Each cost or price index will be an existing index that is widely used to measure the increase in prices for that category of commodities or services. The Commission will give first preference to indexes published by the U.S. Government, but indexes published by private institutions may also be used if widely used and generally accepted. The applicant may submit to the Commission proposed price or cost indexes with its proposed cost estimate format mentioned in condition 7.

(9) *Changes in scope.* Prior to calculating the projected rate base for determining the cost performance ratio, the final cost and schedule estimate will be adjusted to reflect increases and decreases in cost that result from certain events not anticipated in preparing the final cost and schedule estimate, or to reflect agreed changes in values of parameters from those assumed in making the final

estimate. The type and number of such events or changes in parameters and the procedure for adjusting the final cost and schedule estimate will be determined by the Commission pursuant to a future rulemaking, hearing, or order.

(10) *Nonincentive rate of return.* Prior to final certification of the pipeline, the Commission shall specify a nonincentive rate of return on equity that compensates equity investors for any abnormal risks they will bear during the construction of the pipeline, excluding the risk created by the IROR rule. To the extent that equity investors in this pipeline bear greater construction phase risks than investors in other regulated gas pipelines, this rate will be higher than the general range of rates allowed for other pipelines. Once established, this rate will not be altered during the construction phase of the pipeline.

(11) *Operation phase rate of return.* Prior to final certification of the pipeline, the Commission shall specify an operation phase rate of return that is within the general range of rates of return for other pipelines with similar operating risks. This rate of return will be determined separately and independently from the IROR. Pursuant to the Natural Gas Act, throughout the operation of the pipeline, the operation phase rate of return may be altered to reflect changes in rates allowed for other pipelines of similar operating risk or to provide just and reasonable compensation to equity investors.

(12) *Cost of service calculation.* After the initiation of service and during the operating life of the pipeline, the transportation charge will be based on standard procedures for determining cost of service except that the rate of return on equity will be the operation phase rate defined above in condition 11 and the rate base will include a one-time adjustment calculated pursuant to condition 13 below.

(13) *Adjustment to rate base.* Upon completion of construction and commissioning of the pipeline, a conventional rate base will be calculated based on generally accepted procedures and using the nonincentive rate of return defined above in condition 10 as the equity rate of return for determining the allowance for equity funds used during construction. A one-time adjustment to the equity AFUDC account in the rate base will then be calculated in three steps. First, the revenue stream from the after-tax return of equity through depreciation of the rate base and from the after-tax return on equity will be estimated over the life of the pipeline, based on the conventional rate base, on an after-tax rate of return on equity capital equal to the IROR determined pursuant to condition 3 above, and on a financing and capitalization plan approved by the Commission. Second, the present worth of this revenue stream will be calculated using a discount rate equal to the operation phase rate determined pursuant to condition 11 above. Third, the difference between this present worth sum and the equity investment in the pipeline, including the allowance for equity funds used during construction based on the nonincentive rate of return on equity, will be added to the allowance in the rate base for equity funds used during the construction. If the difference is negative, the allowance for equity funds during construction in the rate base will be reduced.

—Footnotes—

[1] 43 FR 20245-20246 (May 11, 1978).

[2] The Commission recognizes that additional incentives to control cost of service on this project are created by the sponsors' interest in insuring marketability for the delivered gas.

[3] We further note that the IROR concept is useful when a selection must be made among competing applications and where the relative ability to control costs is a material factor in the selection. IROR rewards the successful applicant if its performance matches its projections.

[4] In the May 8, 1978, notice, the nonincentive rate was referred to as the "normal rate of return." This was meant to signify the rate which would have been determined in normal regulatory proceedings if the IROR were not being applied. The "normal rate" was widely misunderstood to be the rate earned on normal pipeline operations. Thus, for clarity, the rate of return referred to in the May 8 notice as the "normal rate of return" will henceforth be called the "nonincentive rate."

[5] For purposes of determining cost performance ratios, the term "rate base" is used to refer to capital or investment costs and is not intended to refer to rate base in the conventional sense.

[6] In the notice of May 8, the Commission proposed a one-time adjustment to the rate base upon commissioning or startup of pipeline

operations. This adjustment would have been equivalent in present value to the difference between the incentive rate (determined by the degree of cost control measured by the cost performance ratio) and the nonincentive rate of return. In this notice, we instead propose to make a one-time adjustment equivalent to the difference between the incentive rate and the operation phase rate. In this way, all of the unusual risks faced during the construction period (including risk due to IROR) will be compensated for by the one-time adjustment. Future rate of return determinations will then be based on consideration of the operating risks only.

[7] Some of the comments argue that uncertainties about the future operation of the pipeline will make the present value of the return of equity and the return to equity uncertain and thus make the precise size of the one-time adjustment uncertain. The Commission agrees that is is impossible to predict with certainty such things as throughput, tax rates, operation costs, or ultimate capacity. The type of cost-of-service tariff that this Commission is likely to approve will provide a high degree of certainty as to the return of equity and the return to equity over the life of the project, once the size of the equity investment and the allowed rate of return are fixed.

[8] The project sponsors have already provided some recognition of the changing nature of project risks as the project progresses with the discount schedule for late entry which was made part of their partnership agreement. The Commission endorsed that concept in approving the relevant portion of the partnership agreement by order of June 30, 1978, in docket No. CP78-123 (at pp. 7-11), and seeks to reinforce it with the rate base adjustment methodology.

[9] Act of November 8, 1977, Pub. L. 95-158, 91 Stat. 1268 (1977).

[10] *Decision*, p. 51.

[11] *Decision*, p. 36.

[12] *Report*, p. 123.

[13] In some respects it is less complicated to apply the IROR mechanism to conventional lower 48 pipelines. Because the construction technology and pipeline design are more familiar, there are fewer uncertainties in the cost estimates. Thus, the problem of changes in scope or changes in cost beyond the sponsor' control is reduced.

[14] A conditional import authorization was issued on June 7, 1978. *Northwest Alaskan Pipeline Co.*, Docket Nos. CP78-123, et al.

[15] In the *Decision* (p. 180) it is estimated that an increase in direct capital costs of 124 percent (in constant dollars) over the Mar. 1977 estimates would make the project uneconomic from a national point of view.

[16] A number of comments argue that any IROR schedule which allows for the possibility, no matter how remote, that the allowed rate of return might fall below that of comparable investments in the U.S. economy would be unjust, unreasonable, and confiscatory, depriving investors of their property in violation of the Constitution. In the case of a pipeline for which no IROR mechanism has been established, the Commission concedes that it would normally be unreasonable to lower the rate of return below rates earned in other comparable investments after the pipeline had been constructed and after equity owners had invested their money. However, prior to the expenditure of any funds for construction of this project, this Commission will establish an IROR schedule that will tie the allowed rate to cost control, clearly a valid regulatory purpose. As long as the principles of this mechanism are clearly specified in advance of construction, are fairly applied, and are agreed to by the investors, it can hardly be termed either unreasonable or confiscatory if poor cost control produces a rate of return below that earned on other investments. *cf; FPC* v. *Sierra Pacific Power Co.*, 350 U.S. 348 (1956) and *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 332 (1956) (when a public utility or pipeline enters into a fixed rate contract which becomes unprofitable, the Commission cannot allow a rate increase unless the contract rate becomes so low as to severely impair the ability of the utility to maintain service). Moreover, as in this case "[e]conomic regulation under the commerce power, affecting an industry generally, is not a taking of property if the value of property is thereby reduced or business risks increased." *Southern Louisiana Area Rates Cases* v. *FPC*, 428 F. 2d 407, 428 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

[17] *Decision*, p. 37.

[18] Bank of America and Citibank, letter to John G. McMillian dated June 2, 1978, attached to Alaskan Northwest reply comments.

[19] For example, a minimum bill might be utilized in cost-of-service tariff which would insure debt service, including sinking fund payments.

[20] Here again, there may be restrictions on distribution of return among different contributions to the pool under prior agreements among those contributors. See footnote 8 above.

[21] The cost performance ratio could also be increased by extending the construction schedule without changing direct capital costs.

[22] All capital and operating costs have been increased 5 percent per year to reflect inflation. The per-unit cost of service has then been deflated to 1975 dollars.

[23] The present worth average is that constant charge per unit of gas over the 20-year

period which has the same present worth as the declining transportation charge that would result from a conventional cost of service calculation. A discount rate of 10 percent is assumed in computing the present worth. A different discount rate would change the average, but the relationship between different values would be the same.

[24] The discount rate used is 10 percent.

[25] An IROR schedule that does not reduce the average rate as the cost performance ratio increases exhibits a marginal rate equal to the average rate. The average will decline only if the marginal is less than the average.

[26] Calculated from the ratio $[(2.2)(15.7)-(0.8)(17.8)]/(2.2-0.8)$.

[27] *Pacific Gas Transmission Company*, docket No. RP75-57, opinion No. 811, order modifying initial decision, July 8, 1977. *Columbia Gulf Transmission*, settlement agreement, docket Nos. RP 76-94, 76-95, 76-138, and 75-106 (AP76-1), Mar. 16, 1978.

[28] *Initial Decision on Proposed Alaska Natural Gas Transportation Systems: El Paso Alaska Company*, Docket No. CP75-96, et al., Federal Power Commission, Feb. 1, 1977, pp. 369-370.

[29] *Recommendation to the President: Alaska Natural Gas Transportation Systems*, Federal Power Commission, May 1, 1977, pp. IV-12 to IV-14.

[30] *Decision*, pp. 125 and 163.

[31] Lawrence Fisher and James H. Lorrie, "Rates of Return on Investment in Common Stock," *Journal of Business*, January 1964. "Rates of Return on Investment in Common Stock: Year-by-Year, 1926-65," Journal of Business, July 1968. Irwin Fried and Marshall E. Blume, "Demand for Risky Assets," *American Economic Review*, December 1975. Roger G. Ibbotsen and Rex A. Sinquefield, "Stocks, Bonds, Bills, and Inflation: Year-by-Year Historical Returns (1926-74)," *Journal of Business*, Jan. 1976.

[32] Page 155 of the Report accompanying the President's *Decision* states that overruns are expected to increase direct capital costs for the Alaskan segment from the Mar. 1977 estimate of $1.812 billion to $2.38 billion, excluding AFUDC and in constant 1975 dollars. This would be an increase of 31 percent. On page 157, a comparison of current dollar costs including AFUDC shows an expected overrun of 24 percent for the Alaskan segment ($4.147 versus $3.335 billion) and 10 percent for the Northern Border segment ($1.573 versus $1.427).

[33] A value of the incentive rate (R) can be determined for any value of the cost performance ratio (A) from the formula: $R = [(17)(1.3) + 8(A - 1.3)]/A = 8 + (11.7)/A$.

[34] The average equity rate allowed by this Commission for some 31 natural gas pipeline rate cases in 1976 and 1977 was 12.94 percent.

[35] The break-even cost reduction is calculated by determining the percentage difference in the cost of service with and without the IROR mechanism, for the same cost performance ratio. This is not strictly accurate, since the operating cost component of cost of service does not increase with cost overruns, but is illustrative of the degree of savings in capital costs which are required for the IROR to produce a cost-effective result.

[36] For cost performance ratios greater than 1.6, the IROR mechanism would actually have to cause an increase in construction costs of a certain minimum percentage, before consumers would be worse off with the IROR mechanism in effect. Thus, for example, column (9) of table II indicates that, for a cost performance ratio of 2.2, the IROR mechanism would have to increase costs by more than 5 percent (i.e., a reduction of minus 5.0) before consumers would not benefit from the IROR proposal.

[37] The problem results because a price index measures the inflation for a specified bundle or market basket of commodities. If price increases differ greatly between the commodities, an individual who buys a slightly different combination of commodities could experience a very different actual rate of inflation than the index indicates.

[38] *Decision*, pp. 109-110.

¶ 31,997 Recovery of Changes In Purchased Gas Costs

43 F.R. 50191 (October 27, 1978).

[18 CFR Part 154]

Proposed Rulemaking Which Would Require Interstate Natural Gas Pipelines To Elect To Use Either a Purchased Gas Cost Adjustment Clause, or General Rate Cases, To Reflect in Its Rates Changes in Purchased Gas Costs

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of proposed rulemaking in docket No. RM79-1.

SUMMARY: The notice of proposed rulemaking, if adopted by the Federal Energy Regulatory Commission, would require interstate natural gas pipelines subject to the Commission's rate jurisdiction to elect every 3 years whether to recover changes in purchased gas costs through purchased gas cost adjustment clauses or general rate case filings.

It is the Commission's goal to reduce the time and effort spent reviewing filings to recover purchased gas costs either through general section 4 rate cases filed pursuant to § 154.63 or through PGA clause rate filings. It is also the goal of the Commission to reduce the burden upon pipeline companies by reducing the number of filings which they must prepare and prosecute, as well as to provide more rate stability for distributors and ultimate consumers of natural gas.

DATES: Comments are due on or before November 20, 1978.

ADDRESS: Interested persons may participate in this proposed rulemaking by submitting written data, views, or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Charles E. Bullock, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4232.

The Federal Energy Regulatory Commission (the Commission) hereby gives notices that it proposes to adopt a regulation requiring jurisdictional pipeline companies to elect, on a 3-year basis beginning in 1979, whether to reflect changes in the purchased gas costs as defined by § 154.38(d)(4) of the regulations through purchase gas adjustment (PGA) clauses or through general rate filings made pursuant to 18 CFR § 154.63. Data, views, comments, and suggestions on the matter are invited in order to assist the Commission in its review of the proposal. The Commission requests discussion of the merits of the proposal and alternative means, if any, of realizing its purpose.

BACKGROUND

It is the Commission's goal to reduce the time and effort spent reviewing filings to recover purchased gas costs either through general section 4 rate cases filed pursuant to § 154.63 or through PGA clause rate filings. It is also the goal of the Commission to reduce the burden upon pipeline companies by reducing the number of filings which they must prepare and prosecute, as well as to provide more rate stability for distributors and ultimate consumers of natural gas.

This goal was in part implemented by Commission Order No. 13, issued October 18, 1978 in Docket No. R-406, published also in today's issue which limits to two the number of PGA filings that a pipeline may make in a year and specifies the dates on which the filings are made. However, even though the purpose of Order No. 13 is to reduce the number of PGA filings, that goal may not be realized if the pipelines respond to that order by including changes in purchased gas costs in general section 4 rate filings made pursuant to § 154.63 and by increasing the frequency of such filings. The purpose of this proposal is to avoid substitution of general section 4 rate filings for PGA filings.

A pipeline can recover changes in purchased gas costs in a timely manner either through adoption of PGA procedures or section 4 procedures. Reliance on both are necessary only in cases where a pipeline company seeks to recover purchased gas costs that may not be included in PGA clauses, such as liquefied natural gas (LNG) or synthetic natural gas (SNG), and where a pipeline company can demonstrate to the Commission that it is (1) unable to arrange for financing of

the balances being carried in the deferred account, or (2) is unable to earn its allowed rate of return because there is such a significant difference between the costs of financing the deferred amounts and the carrying charges allowed by the Commission.

Pursuant to this proposal, pipeline companies would be precluded for 3 years from including in section 4(e) rate filings pursuant to § 154.63 changes in purchased gas costs, except in certain specified circumstances, if they have elected to adopt or maintain a PGA clause.

SUMMARY OF THE PROPOSAL

Under the proposal, pipeline companies electing to adopt or maintain PGA clauses would be precluded from including changes in purchased gas costs in general section 4 rate cases, filed pursuant to § 154.63, for a period of 3 years from the date of electing a PGA clause. At the end of the 3 years, if the pipeline had not made a filing to the contrary with the Commission, it would be deemed to have elected to renew its election for an additional 3 years, subject to the provisions of § 154.38(d)(4)(vi). However, when a company could demonstrate to the Commission that it (1) is unable to arrange for the financing of the balances being carried in the deferred account, or (2) is unable to earn its allowed rate of return because there is a significant difference between the costs of financing the deferred amounts and the carrying charges allowed by the Commission, it could request a waiver of the PGA clause election to include in a general section 4(e) rate filing made pursuant to § 154.63, changes in purchased gas costs, as well as changes in other items of cost.

Under the proposal, as under the Commission's present regulations, PGA treatment (§ 154.38) would be applicable only to purchased gas costs as defined by § 154.38(d)(4). The costs of other purchased gas, such as LNG and SNG, cannot, under the present or the proposed regulations, be recovered through a PGA clause except where a company has obtained a waiver of the PGA regulations to allow recovery of these costs through the PGA clause. Thus where a waiver has not been obtained, the company would continue to use section 4 procedures pursuant to § 154.63 to collect those costs in its rates. When a company that had elected PGA procedures made a general section 4 rate filing to recover changes in other costs of operations, including the costs of LNG or SNG, the company would use the unit purchased gas cost reflected in its then effective PGA adjustment. In the section 4 proceeding, the company or any other party would be permitted to place in issue the appropriate volume of purchased gas.

Conforming amendments to § 154.63 have also been proposed.

PUBLIC COMMENT PROCEDURES

Interested persons may participate in this proposed rulemaking by submitting written data, views, or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before November 20, 1978. Each person submitting a comment should include his name and address, identify the notice (docket No. RM79-1), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

(Natural Gas Act, as amended, 15 U.S.C. § 717 et seq., Department of Energy Organization Act, Pub. L. 95-91, E. O. 12009, 42 FR 46267.)

In consideration of the foregoing, it is proposed to amend part 154, chapter I of title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

KENNETH F. PLUMB,

Secretary.

1. Section 154.38 is amended in paragraph (d) by revising the introductory language in subparagraph (4) to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(d) *Statement of rate.* * * *

(4) A natural gas pipeline company may elect to submit a purchased gas cost adjustment clause (PGA clause) to flow through changes in its cost of purchased gas.[1] Natural gas pipeline companies shall elect on a 3-year basis as of January 1, 1979, whether to recover all changes in purchased gas costs through general rate change filings or to recover changes in purchased gas costs through the PGA provisions. If a company elects to adopt or maintain a PGA clause § 154.38(4) shall be applicable. If a company elects to recover all changes in purchased gas costs through general rate changes filings made pursuant to § 154.63 of this part, such election shall be effective for 3 years, during which time the company may not adopt a PGA clause. At the end of the 3 years if the pipeline has not made a filing with the Commission to the contrary, the pipeline shall be deemed to have elected to renew its PGA clause election for an additional 3 years, subject to § 154.38(d)(4)(vi). If a company elects to adopt a PGA clause it may not include changes in purchased gas costs covered by the PGA clause in a general section 4 rate case filed pursuant to § 154.63 unless the commission has granted a waiver of the pipeline's election. To receive a waiver, the pipeline must demonstrate that it is unable to arrange for financing of the balances being carried in the deferred account, or is unable to earn its allowed rate of return because there is a significant difference between the costs of financing the deferred amounts and the carrying charges allowed by the Commission. No PGA clause shall become effective until approved by the Commission. No request for approval of a PGA clause will be considered by the Commission unless the proposed PGA clause indicates the following terms and conditions:

* * * * *

2. Section 154.63 is amended by revising subparagraphs (3) and (4) of paragraph (b) and by revising schedule H(1)-3 of paragraph (f) to read as follows:

§ 154.63 Changes in a tariff, executed service agreement or part thereof.

* * * * * *

(b) *Material to be submitted.* * * *

(3) *Major rate increase.* Class A companies (as defined in Subchapter F, Uniform System of Accounts for Natural Gas Companies, of this chapter) shall submit, in addition to the material required by subparagraph (1) of this paragraph, statements A to M inclusive and O and P described in paragraph (f) of this section. Class B, C, and D companies, defined as above, shall file only statements L, M, N, O, and P. Statement P, which is required to be submitted by all classes of companies, may be furnished not later than 15 days after the date of the filing. A natural gas company filing another major increase in rates or charges within a period of 12 months after the date of filing of statements A through M and O and P or after the end of the test period used therein including the period of adjustments shown on statements A through M may submit for such other increase statements L, M, and N in lieu of statements A through M if the proposed new rate increase is filed to compensate only for an increase in the cost of purchased gas and there has been no material change in the company's facilities, sales volumes, and cost of service other than cost of purchased gas since such prior rate increase was filed. However, pipelines with Commission approved PGA clauses conforming to section 154.38(d)(4) of the regulations shall not be permitted to include changes in purchased gas costs in filings made pursuant to this subparagraph unless they have received a waiver of their PGA election pursuant to § 154.38(d)(4). Pipelines with Commission-approved PGA clauses making filings pursuant to this subparagraph shall reflect the unit cost of purchased gas costs as of the pipeline's latest Commission-approved PGA rate adjustment, unless the piepline has received a waiver of its PGA election pursuant to § 154.38(d)(4).

(4) *Minor rate increase or rate decrease.* Only statements L through N need be filed in addition to the material required by subparagraph (1) of this paragraph. (Statements L through N are not required to make effective rate changes or tariff provisions ordered by the Commission.) A pipeline with an effective Commission-approved PGA clause conforming to § 154.38(d)(4) shall not be permitted to include changes in purchased gas costs in rate filings made pursuant to

this subparagraph unless the pipeline has received a waiver of its PGA election pursuant to § 154.38(d)(4). A pipeline with an effective Commission-approved PGA clause shall reflect in any filing made pursuant to this subparagraph the unit cost of purchased gas cost as of the pipeline's latest Commission-approved PGA rate adjustment, unless the pipeline has received a waiver of its PGA election pursuant to § 154.38(d)(4).

* * * * *

(g) *Description of statements.* * * *

Schedule H(1)-3. a schedule showing either: (a) In the case of a pipeline which has a Commission-approved PGA clause in its tariff, its unit cost of purchased gas as set forth in the pipeline's latest Commission-approved PGA rate adjustment. However, the pipeline may adjust its purchased gas volumes as provided in (b) hereof; or (b) in the case of a pipeline which does not have a Commission-approved PGA clause in its tariff or in the case of a pipeline which has a Commission-approved PGA clause but obtains a waiver of its PGA clause election pursuant to § 154.38(d)(4), the total annual cost of gas purchased for the 12 months of actual experience, the adjustments thereto, and the total adjusted cost for test period, with the data grouped by States and producing areas and detailed by contract or rate schedule designation, field, volumes in Mcf at a common pressure base and price in total for the contracts or rate schedules under which actual or adjusted volumes exceed 1,000,000 Mcf annually. Field purchases under rate schedules where the actual or adjusted volumes are less than 1,000,000 Mcf annually may be grouped by field or producing area. Purchases from pipelines in any volume shall be shown in full detail by rate schedule including splits between demand and commodity charges.

In the event adjustments are made to the volumes of gas taken from any source during the 12 months of actual experience, a detailed explanation and data in support of the adjusted volumes shall be furnished. No adjustments are to be made to reflect the attachment of new gas supplies unless both the filing company and the supplier have each obtained the required permanent or temporary certificates of public convenience and necessity and the necessary facilities by both are or will have been in operation during the test period.

In the event the adjustments to volume aggregate more than 10 percent of the total volume of gas purchased during the 12 months of actual experience, and are due to change in gas purchase pattern or additional gas supply, the minimum take-or-pay-for quantities for each source of supply, applicable at the end of the test year period, and the reasons for making such adjustments shall be submitted.

If the company purchases and sell gas under exchange agreements, the method of recording on books, total gross volumes exchanged, net dollar amounts involved and details of each major exchange shall be submitted.

—Footnote—

[1] For the purposes of this paragraph, purchased gas cost represents the cost of well-head purchases, field line purchases, plant outlet purchases, transmission line purchases, and pipeline production from leases acquired on and after Oct. 7, 1969. Nonconcurrent exchange transactions may be reflected as a cost of purchased gas. If a company has underground storage, the cost of purchased gas included in accounts 800, 801, 802, 803, and where applicable, account 806, shall be debited or credited to reflect the net injections or withdrawals from underground storage. This adjustment shall be prorated between pipeline and producer supply. New pipeline supplies (contractual daily delivery obligations) and liquefied natural gas, synthetic natural gas, and gas from coal gasification shall not be reflected in a PGA clause without prior Commission approval.

¶ 31,998 Regulations Implementing the Natural Gas Policy Act of 1978

43 F.R. 53270 (November 15, 1978).

[18 CFR Parts 3, 157, 270, 271, 273, 274, 275, 276, 284]

[Docket No. RM79-3]

REGULATIONS IMPLEMENTING THE NATURAL GAS POLICY ACT OF 1978

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of Proposed Rulemaking

SUMMARY: The Natural Gas Policy Act of 1978 (NGPA), enacted November 9, 1978, takes effect with respect to certain first sales of natural gas delivered on or after December 1, 1978. The new statutory provisions relating to pricing of natural gas and other issues must, therefore, be implemented by regulation by that date. These proposed implementing regulations are being issued for a brief public comment period prior to promulgation of interim regulations. The Commission will then receive comments on the interim regulations for 60 days and will revise the interim regulations as appropriate.

DATE: Written comments by November 20, 1978.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 N. Capitol St., N.E., Washington, D.C. 20426, (Reference Docket No. RM79-3).

FOR FURTHER INFORMATION CONTACT:

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Subpart D—Assignment of Contractual Rights to Receive Certain Gas

I. Introduction

On November 9, 1978, the Natural Gas Policy Act of 1978 (NGPA) was signed into law. By passage of the NGPA, Con-

gress has mandated a new legislative framework for the regulation of most facets of the natural gas industry. The new law affects sales, transmission and distribution of natural gas. The previously controlling federal regulatory statute, the Natural Gas Act (NGA) has in many respects been limited, replaced or superseded by the NGPA.

A primary effect of the NGPA is the substitution of a series of specific statutory maximum price levels applicable to discrete types of "first sales" of natural gas for the previously established system of price regulation of interstate sales of natural gas which had been grounded in a cost-based methodology. An important distinction between producer regulation under the NGA and the NGPA is the expansion of the Federal Energy Regulatory Commission's (Commission) jurisdictional scope to encompass not only sales made in interstate but in intrastate commerce as well. Under the NGPA, all first sales of natural gas are controlled by the maximum statutory ceiling rates and as a result, it is unlawful for any person to sell natural gas at a price in excess of the statutory maximum regardless of whether the sale occurs in the inter- or intrastate market.

The Commission wishes to call specific attention to the provisions of section 101(b)(g) of the NGPA. The Congress, by that provision, emphasizes and makes clear that the maximum lawful prices under the NGPA are *ceiling* prices and do not supersede or nullify the effectiveness of any contractual agreement to pay a lower price. Therefore, the Commission cautions producers not to assume entitlement to any NGPA ceiling price which is higher than their contract prices.

The Commission is directed to administer essentially all of the NGPA and is authorized to perform any and all acts and to prescribe and issue such rules and orders as it finds necessary or appropriate to carry out its functions under the NGPA. The proposed regulations, contained in this notice, mark the first step in carrying out the basic responsibilities for implementation and administration of the Act and provide a mechanism for transition from the NGA regulating regime to the NGPA scheme.

The NGPA is divided into six titles:

I. Pricing

A. Price Controls Applicable to Sales of Natural Gas

B. Decontrol of Certain Natural Gas Prices

II. Incremental Pricing

III. Additional Authorities and Requirements

A. Emergency Authorities

B. Other Authorities and Requirements

IV. Natural Gas Curtailment Policies

V. Administration, Enforcement, and Review

VI. Coordination with the Natural Gas Act, Effect on State Laws

The regulations proposed here do not implement all titles under the NGPA. Rather, the regulations propose to deal with those areas demanding the most expeditious treatment.

This first group of regulations is designed to set in motion the new scheme for pricing of first sales of natural gas and to provide mechanisms for implementation of provisions of the NGPA covering certain arrangements for transportation of natural gas. However, before setting out in detail a full description of the specific regulations proposed, a summary of the most salient features of the NGPA, the effect on regulation under the NGA, and a capsule description of the implementing regulations and corollary modifications of regulations under the NGA, may be useful.

The Legislative Scheme of the NGPA

The nature and scope of Commission regulation of producer sales under the NGPA has been substantially transformed from utility-type regulation of a limited market to what is essentially price regulation of an entire national market. Under the scheme set up by the NGPA, there exist two major categories of first sales: those requiring a prior determination of eligibility to be made by a jurisdictional federal or state agency before collection of the maximum lawful price and those not explicitly requiring such a determination. A decision as to whether a first sale falls into a category requiring a determination is fundamental. A decision to seek a determination

triggers quite different regulatory consequences than an opposite conclusion.

Although the Commission may be called upon to return to the cost-based, just and reasonable methodology within the meaning of the NGA in establishing rates in excess of the NGPA ceiling prices, the basic administration of the pricing provisions of the NGPA will be undertaken from an entirely different perspective. The Commission will no longer inquire into producer costs or set permissible rates of return for producers. Instead, the Commission's focus will center on whether geological information, production history, field records, prior contractual relationships and information of a similar nature support the categorization for pricing purposes claimed by producers.

Another crucial factor in anticipating what regulatory treatment will be accorded producer sales of natural gas is whether gas is "committed or dedicated" for purposes of NGA regulation. The limitations on NGA regulation as a result of enactment of the NGPA will be addressed in another section of this preamble. However, the distinction between gas which is deemed to be subject to continuing regulation under the Natural Gas Act and gas which falls solely within the NGPA regulatory format is significant and affects both pricing and non-pricing regulation of producer matters.

For categories of gas requiring a prior determination by a federal or state agency, the Commission's function is more in the nature of an appellate body, reviewing, on a substantial evidence basis, the factual determinations of the appropriate jurisdictional agency with the right of disapproval in the event the initial determination is not adequately substantiated. The Commission rules reflect this role and prescribe the basic and minimum factual foundation necessary to meet its review responsibilities without directly interposing the Commission into the procedural functioning of the jurisdictional agency. The review process of initial determinations begins when notice is received of a jurisdictional agency's determination with the appropriate supporting material specified in Part 274 of the proposed regulations. In the absence of a reversal, the determination of the jurisdictional agency becomes final and no longer subject to review unless based on any untrue statement of material fact or upon any omission of material fact which omission was misleading.

Categories of first sales explicitly requiring that a determination as to qualification to collect the maximum lawful price be made by either a jurisdictional federal or state agency are:

Section 102 which sets a maximum lawful price for first sales of new natural gas (gas produced from a new lease on the Outer Continental Shelf (OCS) or certain new onshore wells) and gas produced from any old OCS lease which was from a reservoir discovered after July 27, 1976;

Section 103 which sets a maximum price for first sales of new onshore production wells;

Section 107 which sets a maximum lawful price for first sales of high cost natural gas including gas produced from geopressurized brine, coal, seams, Devonian shale or gas produced under other conditions the FERC determines to present "extraordinary" risks or costs; and

Section 108 which sets the maximum lawful price for first sales of stripper well natural gas.

An essential element in the regulatory system established with respect to categories requiring a prior determination is the provision for interim collection procedures by producers awaiting a final determination or the outcome of a review of such determination. The Commission has a concomitant power to require refunds from the producer if the gas eventually qualifies for a lower price. Section 503(e) sets out this collection and refunding procedure.

Part 273 of the regulations states the prerequisites for interim collection. First, the Commission has established a "transitional rule" to permit the collection by producers of the section 109 price if a producer files for a determination by March 1, 1979. Additional rules are established for interim collection pending and following a state or federal agency determination.

Those first sales of natural gas not requiring a prior determination to be made by a jurisdictional federal or state agency

are tied to previously existing contractually set prices or price levels established by the Federal Power Commission or this Commission. First sales not requiring a prior determination under the NGPA are:

Section 104 which incorporates by reference the just and reasonable rates established under the NGA for first sales of gas committed or dedicated to interstate commerce on the day before the date of enactment of the NGPA;

Section 105 which establishes maximum lawful prices for first sales under existing contracts of natural gas not previously committed or dedicated to interstate commerce; and

Section 106 which establishes maximum lawful prices for first sales under interstate and intrastate rollover contracts;

Section 109 which establishes the maximum lawful price for first sales of natural gas from the Prudhoe Bay in Alaska and categories of gas not otherwise covered by other sections of the NGPA.

The Commission has general administrative and enforcement authority under the NGPA and the NGA to order refunds in cases where the maximum lawful price level has been improperly exceeded.

Effect of the NGPA upon Continued NGA Regulation

As stated previously, natural gas which remains committed or dedicated to interstate commerce on the day before the date of enactment of the NGPA or which is not specifically exempted from the jurisdictional consequences of commitment or dedication by the NGPA, remains subject to all the nonprice regulatory requirements of the NGA. An important aspect of continued NGA regulation is the requirement that a producer file an abandonment application with the FERC pursuant to section 7(b) of the NGA before terminating service to the interstate market or before abandonment of facilities used to render interstate service. Additionally, although price regulation of first sales by producers of gas committed or dedicated is now governed by the NGPA, sections 104 and 106(a) are grounded in previously established rates under the NGA. As a result, producers wishing to establish their right to collect under these sections will be required to make a filing under their rate schedules under the NGA. On November 16, 1978, the Commission intends to amend its previously existing filing requirements to provide new procedures governing these rate increase filings.

If gas is not committed or dedicated to interstate commerce as defined in section 2(18) or is exempted from the jurisdiction of the NGA under section 601(a)(1)(B) as high cost natural gas, new natural gas, or natural gas produced from any new onshore production well, the prior framework of utility-type regulation under the NGA no longer applies.

If natural gas sales are freed from the requirements of the NGA, several adjuncts to NGA regulation are obviated. First, there is no longer any necessity for a producer to seek certification of the sale as serving the public convenience and necessity. The replacement for this requirement under the NGPA is limited to the state determination mechanism and the pricing limits established in the NGPA. New sales in interstate commerce no longer require certification as a prerequisite to commencement of deliveries. Nor does the requirement for abandonment authorization before termination of deliveries of natural gas exist with respect to natural gas no longer subject to NGA regulation. In the case of first sales of natural gas not previously committed or dedicated to interstate commerce or exempted from NGA regulation, tariff filings and rate increase applications are dispensed with. (Of course, specific requirements for filing to establish the right to collect the maximum lawful price levels exist under the regulations and annual reporting will be required under the NGPA in many instances. However, the nature of these filings, which are in many cases one-time notification type filings is quite different from the rate filings previously required under the NGA.)

For natural gas which on the date of enactment was committed or dedicated but which is exempted from the NGA under section 601(a)(1) of the NGPA, there are substitute mechanisms for NGA section 7(b) abandonment authorization. These substitute provisions, intended to provide a degree of certainty to purchasers dependent upon a predictable natural gas supply, are found in section 315 of the NGPA. The Commission has not at-

tempted to implement these sections in the initial implementing regulations. It is our intent to do so in the near future. That section gives the Commission dual authority to establish by rule or order the minimum duration of any contract (other than an existing contract) for the purchase of natural gas and to require by rule right of first refusal with respect to any gas committed or dedicated to interstate commerce before the date of enactment if such gas is high cost gas, new natural gas or natural gas produced from any new, onshore production well.

Indirectly, NGA regulation is affected by the operation of section 601(b) and (c) of the NGPA. Section 601(b) provides that any amount paid in any first sale of natural gas shall be deemed to be just and reasonable if such amount does not exceed the maximum lawful ceilings established by the NGPA or if there is no maximum lawful price applicable by reason of elimination of price controls. Section 601(c), the guaranteed passthrough provision, states that the Commission may not deny, or condition the grant of any certificate under section 7 of the NGA based upon the amount paid in any sale of natural gas if the amount paid meets the standards of section 601(b) and is, therefore, by statutory fiat, just and reasonable. Additionally, the Commission may only deny the recovery by any interstate pipeline of any amount paid with respect to the purchase of natural gas under section 601(b) to the extent the Commission determines that the amount paid was excessive due to fraud, abuse, or similar grounds.

Finally, included in the implementing regulations are provisions covering certain transportation service by both interstate and intrastate pipelines. Provision is made for intrastate pipeline sales and for the assignment of natural gas excess to their requirements. Also, the Commission has revised its regulations previously applicable to emergency transactions and revised the procedure and the standards for emergency sales of natural gas for this winter's heating season.

General Outline of Implementing Regulations

The proposed regulations add two new subchapters to the Commission's regulations in Chapter I of Title 18. New Subchapter H (Parts 270 through 276) contains the new producer regulations under the NGPA. Part 270 sets forth general rules applicable to the entire subchapter. Maximum lawful prices under NGPA sections 102 through 109 are implemented in Part 271. Part 273 provides for interim collections and refunds, while determinations of eligibility by state and federal agencies and Commission review of those determinations are provided for under Parts 274 and 275. Finally, Part 276 covers reports.

New Subchapter I will cover regulations under the NGPA other than those relating to producer regulation. The current proposal includes only Part 284, which implements the Commission's authority under sections 311 (relating to certain pipeline sales and transportation of natural gas) and 312 (relating to assignment of intrastate pipeline's contractual right to receive surplus natural gas). Regulations relating to other authorities of the Commission will be added later under Subchapter I.

The proposed regulations would also delete sections 2.68, 157.22 and 157.29 of the Commission's regulations in Subchapters A and E, respectively, and add new provisions to cover emergency transactions for the current heating season.

To assist the reader and guide comment, a brief description of each part and subpart is included as a preamble to the text of the regulation. The statutory requirements that certain of our implementing regulations be fashioned and made effective on December 1, 1978, has not permitted the Commission to provide as full and detailed an explanation of its regulations as we would have liked. However, before any regulation is placed into effect (with or without modification) we expect to be able to add greater substance to the explanatory materials, guided by the written comments of interested parties received in response to this invitation for views.

II. Summary of Proposed Regulations

Part 270

Part 270 prescribes rules and definitions that apply to Subchapter H. Subpart A contains the general rules and definitions. Subpart B contains special rules.

The general rules of § 270.101 relate to the application of maximum lawful pricing provisions of the NGPA. This section makes it unlawful for any person to sell natural gas at a first sale at a price which is greater than that permitted under Part 271. This section also sets out general provisions governing the determinations of eligibility to collect maximum lawful prices and describes the categories of natural gas for which prior determinations are to be made. In addition, this section makes it clear that the pricing provisions of Part 271 do not supersede or nullify contract provisions establishing prices below the applicable maximum lawful price. Finally, this section provides that any collection of maximum lawful prices is subject to refund obligations.

Section 270.102(a) provides that terms defined in the NGPA have the same meaning for purposes of these regulations unless further defined. Some terms used in individual sections or subparts are defined therein. Those used in more than one Subpart are defined in § 270.102(b). These include "production in commercial quantities," "crude oil," "surface location," "intrastate contract," "successor to an existing intrastate contract," and "intrastate rollover contract." The term "jurisdictional agency" is defined in § 270.103, which includes a table of agencies by state.

The special rules of Subpart B apply to first sales of natural gas and the maximum lawful prices which apply to such sales. Section 270.201 provides that the maximum lawful price for a first sale of natural gas produced from multiple wells, properties or reservoirs which have different applicable maximum lawful prices will be the weighted average of the maximum lawful prices applicable to each well, property or reservoir.

Section 270.202 provides that a person who purchases natural gas at a first sale and subsequently resells the gas in a transaction which is also a first sale (a "reseller") is, with respect to maximum lawful prices, subject to the same restrictions, as modified by this section, as the initial first seller. In addition, these resellers are obligated to make and retain records respecting such sales.

Section 2(21)(B) of the NGPA states that a sale of natural gas by a pipeline or distribution company is not a first sale unless the sale is "attributable to volumes of natural gas produced" by such company. Section 270.203 delineates certain situations in which a sale of natural gas by these companies is not to be considered a first sale of gas attributable to volumes produced by the companies.

Finally, § 270.204 presents the technical information necessary to determine the number of British thermal units (Btu's) per unit volume of natural gas. This is necessary because maximum lawful prices for first sales of natural gas are stated in terms of dollars per million Btu's.

Part 271—Subpart A

Subpart A of Part 271 sets out, in summary tables, the pricing provisions applicable to certain categories of first sales of natural gas delivered in the months of December, 1978, and January, 1979. It also provides the method and the inflation adjustment factors to be used for calculating maximum lawful prices for those categories of gas for which prices cannot be derived from the summary tables. These latter categories are ones for which maximum lawful prices must be calculated by the seller.

Section 271.102 sets out the methodology by which maximum lawful prices are to be calculated. The procedure involves adjustment for inflation and requires only simple multiplication. The price for a given month is calculated by multiplying (1) the price which was allowed for the sale of natural gas delivered in the preceding month, by (2) a single adjustment factor which is published by the Commission. The adjustment factor, termed the "monthly equivalent of the annual inflation adjustment factor," is computed using the method of calculation prescribed under section 101(a) and (b) of the NGPA. These calculations will be made by the Commission and published at least 5 days before the beginning of any month for which the factor will apply.

The first price from which all maximum lawful prices are to be calculated is termed a "base price." This price varies according to the category of natural gas for which a calculation is to be made. Once this price is known the calculation can proceed, month-to-month,

until the applicable monthly maximum lawful price is determined.

By way of example, assume that a calculation is to be made for natural gas subject to § 271.402(c)(1) for which a just and reasonable rate of $1.00 was in effect. The calculation is to be for the December, 1978, maximum lawful price. First an "applicable monthly price" for November, 1978 must be calculated. This calculation is done by taking the price for April, 1977 ($1.00) and subjecting it to monthly inflation adjustments for all months between April, 1977, and November, 1978. A price for May, 1977, is calculated by multiplying $1.00 by 1.00636, the applicable monthly equivalent of the annual inflation adjustment factor for May, 1977, as presented in the table accompanying § 271.102(c). The result, rounding to the nearest mill, is $1.006. This price is the base price which must then be multiplied by 1.00636, the applicable factor for June, and is again rounded to the nearest mill to reach a price of $1.012 which is then the price for June, 1977. This price, in turn, becomes the price for the month of July, 1977, and must then be multiplied by the monthly equivalent of the annual inflation adjustment factor for July, 1977 (1.00431); and so on through the monthly iterations. The result should be a price of $1.115 for the month of November, 1978. At this point, the maximum lawful price applicable for deliveries made in December, 1978, can be determined. This is done by multiplying the November price of $1.115 by 1.00581, the factor which applies for December. The result is a maximum lawful price of $1.121 for that month.

This example is chosen to exhibit the calculation which § 271.402 will require of some sellers. Sellers subject to either the § 271.502 or § 271.602 pricing provisions will have prices based on the contract price per MMBtu on November 9, 1978, or in the case of rollover contracts, the month in which the rollover occurs. In either event, only a single multiplication need be made to determine the next month's maximum lawful price.

The monthly equivalents of the annual inflation adjustment factors are presented in the table accompanying this section. The change which occurs for each quarter up through the second quarter of 1978 reflects changes in the GNP implicit price deflator. The monthly factors calculated for both the third and fourth quarters of 1978 and the first month of the first quarter of 1979 are all the same because of the late publication of GNP implicit price deflators and the special provision of section 101(a)(3) of the NGPA to use the latest figures available as of the date of the statute's enactment for the calculation of such factors.

Part 271—Subpart B

Subpart B of Part 271 implements section 102 of the NGPA which establishes a maximum lawful price for "new natural gas" and for "natural gas produced from a new OCS reservoir on an old OCS lease." These terms are defined by reference to the NGPA.

Section 271.204 contains a special rule for vertical measurement of the 1,000 foot distance between completion locations necessary for some determinations under this subpart. The rule clarifies the measurement methodology for completions made by perforation and for "openhole" completions. In addition special rules are provided for the statutory terms "capable of producing in paying quantities" and "suitable facilities."

Part 271—Subpart C

Subpart C of Part 271 implements section 103 of the NGPA and applies to first sales of natural gas from new onshore production wells. Section 103(c) of the NGPA defines a new onshore production well as one spudded on or after February 19, 1977, which complies with any applicable well-spacing requirements. Wells which do not comply with well-spacing requirements or are drilled into existing proration units do not qualify for the new onshore production well prices unless they meet the requirements of the special rule set out in § 271.304.

The special rule is in two parts. The first part, paragraph (c), provides that for wells spudded on or after December 1, 1978, the proration unit requirement can only be satisfied if the jurisdictional agency finds that the well is necessary to effectively and efficiently drain a portion of a reservoir covered by the proration unit, which cannot be so drained by any existing well within the unit. Such a finding must involve a redefinition of the proration unit or alteration of or an ex-

ception to otherwise applicable well-spacing requirements.

Paragraph (d) of the rule recognizes that wells drilled between February 19, 1977 and December 1, 1978 may qualify for the price established in section 103. The rule permits such wells to qualify if the agency reviews its preexisting record and determines that it explicitly or implicitly made the same finding necessary for wells spudded after December 1, 1978.

The proposed special rule further provides that in the absence of either an explicit finding or a demonstration by the agency that such a finding was implicit in its authorization to drill the well, the application for a determination will be denied.

The Commission is particularly interested in obtaining comments on this special rule so that it may further consider whether the proposed approach is the best method of implementing section 103 of the Act.

Part 271—Subpart D

Subpart D of Part 271 implements sections 104 and 106(a) of the NGPA. These sections prescribe the maximum lawful price for the first sale of natural gas which was committed or dedicated to interstate commerce on November 8, 1978, and for which a just and reasonable rate under the Natural Gas Act was in effect. Under section 104, the maximum lawful price is the just and reasonable rate for each vintage of gas established by the Commission as of April 20, 1977, as adjusted monthly for inflation from that date forward. Just and reasonable rates established by the Commission after April 20, 1977, constitute the ceiling rates under section 104 and are not generally adjusted for inflation. Section 106(a) prescribes the maximum lawful price for rollover contracts executed after November 9, 1978.

The interim regulations set forth the maximum lawful price applicable to each vintage of gas and define the various vintages of gas established by the Commission's national or area rate opinions. Rules for calculating the maximum lawful price applicable to natural gas for which a non-vintage just and reasonable rate was not previously established under special relief and optional procedures are also included in this subpart.

Section 271.402(a) of Subpart D includes a table of maximum lawful prices for each vintage of previously committed or dedicated natural gas. Transition from the Natural Gas Act prices to the NGPA prices affects two of the prices included therein differently from other categories. First, the price established in section 106(a) of the NGPA for sales by small producers of rollover contract gas is less than the rate such producers would have received for the same category of gas under the Natural Gas Act. Pursuant to § 157.40(c)(1) of this chapter, small producers were entitled, under the Natural Gas Act, to 130% of the maximum base rate established by the Commission for rollover contracts. Thus, for replacement contracts entered into prior to November 9, 1978, section 104 of the NGPA, which is keyed to the rates previously established by the Commission, prescribes a rate reflecting this 30% differential for sales by small producers. However, for contracts rolling over on or after November 9, 1978, section 106(a) prescribes a rate of 54 cents per MMBtu, as adjusted for inflation from April 20, 1977, for both large and small producers. As a result of this anomaly, a small producer who executed a rollover contract prior to November 9, 1978, would be entitled to a rate of 77.1 cents per MMBtu as of December 1, 1978, whereas a small producer who executed a rollover contract on or after November 9, 1978, would be entitled, under section 106(a), to a rate of 60.3 cents per MMBtu.

In order to prevent a small producer from receiving a rate under the NGPA lower than that to which he would be entitled under the Natural Gas Act, the Commission finds it necessary to invoke our authority under section 106(c) of the NGPA. This section provides that the Commission may prescribe a maximum lawful price higher than would otherwise be applicable under section 106 if such higher rate is determined to be just and reasonable within the meaning of the Natural Gas Act. The Commission finds, pursuant to this section, that the rate previously established by the Commission for small producer replacement contract gas is just and reasonable within the meaning of the Natural Gas Act, and should be made applicable to small producer sales of rollover contract gas. The price so determined is 70.2 cents per

MMBtu as of December 1, 1978. This price may be increased, in accordance with Opinion Nos. 770, *et seq.*, and Opinion Nos. 742, *et seq.*, by an amount not to exceed 1.3 cents per MMBtu per annum commencing on January 1, 1979, and the first day of every year thereafter for the term of the contract dedicating the subject gas for sale in interstate commerce.

We note that this price is still not identical to the 77.1 cents per MMBtu price prescribed in the table for small producer sales of replacement contract gas. The price in the table was determined by adjusting for inflation the April 20, 1977, price of 70.2 cents per MMBtu established by the Commission for replacement contract gas. We invite the submission of data, views and arguments on or before December 15, 1978, regarding the question whether, under the standard set forth in section 106(a), the 70.2 cents per MMBtu rate applicable to small producer rollover contracts should be found not just and reasonable, and the just and reasonable rate should be raised to the 77.1 cents per MMBtu rate as adjusted for inflation in months following December 1978.

A second transition problem exists regarding the large producer rate for rollover contracts prescribed in section 106(a). Such rate is determined by applying the inflation adjustment factor to an April 1977 rate of 54 cents per MMBtu in order to arrive at a December 1, 1978, rate of 60.3 cents per MMBtu. However, the large producer rate for replacement contracts was 53 cents as of April 20, 1977, which when adjusted for inflation translates to a rate of 59.3 cents per MMBtu as of December 1, 1978. Again, we note that the only difference between a replacement contract and rollover contract is that the latter is executed on or after November 9, 1978. In view of this disparity in treatment for the same types of sales of natural gas, we invite the submission of data, views and arguments on or before December 15, 1978, regarding the question whether, under the standard set forth in section 106(a), the large producer replacement contract rate of 59.3 cents per MMBtu should be found not just and reasonable, and the just and reasonable rate should be raised to the 60.3 cents per MMBtu rate for large producer rollover contracts.

Under § 271.402(c)(2) of these regulations any "just and reasonable" rate established by the Commission for a sale of natural gas after April 20, 1977, and prior to November 9, 1978, is the maximum lawful price applicable to such sale if higher than the otherwise applicable price prescribed in § 271.402 (a) or (c)(1). As to producer applications under the optional procedure regulation set forth in § 2.75 of this chapter, a "just and reasonable" rate is that rate established by the Commission in its final order on such applications.

Under § 271.403 of these regulations, we have provided a special rule regarding a carrying charge adjustment for advance payments. In Opinion No. 770-A, the Federal Power Commission recognized that capital generated through the advance payment program was no longer required to bring additional gas supplies to the interstate market. The Commission noted that the rate level set forth in that opinion was designed to achieve the capital formation objective. Accordingly, the Commission found that as to additional advance payments made after the issuance of that opinion, it would be inequitable to require consumers also to pay the carrying charges on these amounts.

The Commission determined that producers who accept advance payments after the date of the opinion should reduce the rate prescribed therein for post-1974 gas which was committed under any further advance payments by the cost of the advances borne by consumers.

Because of these same considerations, we have provided in § 271.403 for the same adjustment in the rates charged by producers for post-1974 gas. Producers subject to this carrying charge rule would be required to reduce their rates by 83 cents per MMBtu for all deliveries made pursuant to the applicable advance payment agreement until the total amounts so deducted equal the amounts collected by the purchasing pipeline from its customers as a result of including the applicable advance payments in rate base.

Part 271—Subpart E

Subpart E of Part 271 implements section 105 of the NGPA by setting forth the procedure for determining the maximum lawful price for first sales of natural gas under existing, or successors to existing, intrastate contracts.

Although throughout the proposed regulations the reference is to *intrastate* contracts, it should be noted that these provisions apply to contracts which govern the sale of natural gas which was not previously committed or dedicated to interstate commerce on November 8, 1978 (the day before the date of enactment of the NGPA). Included in this category is any gas which was sold in interstate commerce under an emergency sale, a limited term certificate, and certain direct sales for which specific transportation certificates had been issued by the Commission.

Under Subpart E of the proposed regulations the maximum lawful prices depend upon the relationship that existed on November 9, 1978, between the existing contract price and the new natural gas price. Under § 271.502(a), if the contract price is less than the new natural gas price, then the maximum lawful price will be, pursuant to section 105(b)(1) of the NGPA, the lower of the new natural gas price or the price under the terms of the existing contract on November 9, 1978, (as such price may be changed from time to time in accordance with contract terms in effect on November 9, 1978). Under § 271.502(b), if the existing contract price exceeded the new natural gas price on November 9, 1978, then the maximum lawful price will be the higher of the new natural gas price or the contract price limited to escalation by the monthly equivalent of the annual inflation adjustment factor.

The term "contract price" is defined in § 271.504 to mean the price per MMBtu charged for deliveries of natural gas occurring on November 9, 1978, or the price that would have been charged had deliveries occurred on that date.

Subpart E sets forth a special rule limiting the price effects of modifications of contract terms executed after November 9, 1978. Section 271.505(a) provides that no such modification may have the effect of requiring the purchaser to bear any greater costs than would have been borne under the terms of the existing contract. Section 271.505(b) stipulates that no such modification may provide for an earlier date for deliveries than provided for in the existing contract. While non-price terms may be changed by such a modification, they may not result in a higher contract price.

The Commission is particularly interested in receiving comments on these special rules.

Part 271—Subpart F

Subpart F of Part 271 implements section 106(b) of the NGPA. Subpart F applies to first sales of natural gas under intrastate rollover contracts, and sets forth the procedure for determining the maximum lawful price applicable to such sales. Two tables are provided in the regulation: one for the prices permitted to be charged under section 106(b)(1), and the other for prices permitted to be charged under section 106(b)(2).

The maximum lawful price under Subpart F for first sales of natural gas under section 106(b)(1) of the NGPA is to be the higher of: (a) the maximum price under the expired contract in the month of expiration as escalated by the monthly equivalent of the annual inflation adjustment factor, or (b) $1.00 per MMBtu escalated from April, 1977 to be escalated by the same inflation adjustments.

The table in § 271.602(b) provides for the maximum lawful price for natural gas to which may be charged for certain State or Indian royalty natural gas production interests under section 106(b)(2) of the NGPA.

Subpart F also contains a special rule similar to § 271.505 regarding clauses in rollover contracts that have the effect of shifting production-related costs to the purchaser without a concomitant decrease in the sale price of natural gas. Section 271.605 mandates that a provision in a rollover contract that differs from the comparable provision of the expired "existing contract" and which has the effect of shifting such production-related costs to the purchaser, shall be treated as if it is an increase in the first sale price. As in the case of § 271.505, the Commission invites comments and views on this special rule.

Part 271—Subpart G

Subpart G of Part 271 implements section 107 of the NGPA, which applies to first sales of natural gas from deep high-cost natural gas wells. It contains a special rule in §271.704 clarifying the method of determining the depth of a well.

Section 107 of the Act authorizes the Commission to establish incentive prices for gas from geopressurized brine, occluded natural gas from coal seams, and gas from Devonian shale. It also authorizes the Commission to establish incentive prices for gas produced under other conditions as the Commission determines present extraordinary risks or costs.

The proposed regulation does not address the question of incentive prices for the three statutory categories mentioned above, nor does it address the questions of whether additional categories should be designated as "high cost gas." The Commission will address these issues in a separate public notice in which it will seek comments regarding what, if any, incentive price would be appropriate for each of these categories, and what additional gas is produced under conditions which present extraordinary risks or costs.

Part 271—Subpart H

Subpart H of Part 271 implements section 108 of the NGPA, which is applicable to first sales of natural gas produced from stripper wells. This subpart contains definitions of terms used in section 108, and prescribes several special rules intended to assist in the application of section 108.

Section 108 of the NGPA provides a maximum lawful price for stripper well natural gas, and prescribes a definition for stripper well gas. According to the general rule prescribed in section 108(b)(1) of the statute, a well is a stripper well if, during the 90-day production period ending within 120 days of the date on which the filing is made it produced nonassociated gas at a rate which did not exceed an average of 60 Mcf per production day, and if the well produced at its maximum efficient rate of flow during such 90-day period. Section 108(b)(2) also provides that a well may continue to qualify as a stripper well if production exceeds 60 Mcf per day, during any 90-day production period, if the increased production was the result of the application of recognized enhanced recovery techniques.

Section 271.803 of Subpart H defines "recognized enhanced recovery techniques" and "nonassociated gas." The definition of "recognized enhanced recovery techniques" includes processes or equipment which increase the ultimate recovery of gas from a well and excludes techniques or equipment necessary for normal well maintenance, repair, or replacement.

The proposed definition of "nonassociated natural gas" would permit a stripper well to qualify under this subpart if it produces an average of no more than one barrel of oil per production day during the 90-day production period which is the basis of the determination of stripper well status. Because of the significance of this definition comments and suggestions on this question are specifically invited.

Section 271.804 sets forth special rules which interpret and apply terms used in the NGPA. Section 271.804(a) and (b) concern the methodology for measurement of production from a well. Section 271.804(a) states that the volumetric basis for determining the rate of production from a single well is the total volume of gas produced from all producing intervals of the well. Section 271.804(b) applies when the wells are not individually metered. In this circumstance, jurisdictional agencies may average rates of production in order to determine whether particular wells are stripper wells. For example, six wells may be attached to a single meter. If the meter showed deliveries averaging 240 Mcf per production day or less during the relevant period, presumptively all wells would qualify. If, on the other hand, deliveries from the six wells averaged 370 Mcf per production day, then presumptively, none of the wells would qualify. In either case, alternative evidence may be offered in rebuttal to establish qualification or the lack of qualification.

Section 271.804(d) is a rule applying the statutory requirements with respect to "maximum efficient rate of flow" (MER). The proposed rule provides that a well is presumed to have produced at its

MER during the 90-day production period if it produced an average volume of 60 Mcf or less per production day during a 12-month period ending concurrently with the 90-day production period which is the basis for the determination. There may, however, be situations in which a 12-month production history is not available. In such situations the jurisdictional agency may look to other types of evidence, such as flow tests, which would measure the production capability of a well, or it may defer making the determination for a time necessary to acquire and submit a 12-month production history. If the agency defers the determination, the applicant would, if contractually entitled, be able to collect the stripper price subject to refund.

Section 271.804(e) is a special rule which permits wells to retain stripper status despite increases in production above the 60 Mcf per day level, provided the increase is attributable to seasonal fluctuations. Jurisdictional agencies may make the determination that a well is seasonally affected on the basis of production history over a 24-month period if production from the well has not and cannot reasonably be expected to exceed an average of 60 Mcf per day for any 12-month period.

Section 271.805 is a rule implementing section 108(b)(2) of the NGPA. The rule disqualifies wells which, subsequent to the jurisdictional agency determination, produce quantities of gas in excess of the amounts permitted by the law and this subpart.

The proposed rule provides for a reporting mechanism to monitor the continued qualification of the well. Both the operator of the well and the purchaser of the gas must report any increase in gas production above an average of 60 Mcf per production day for any 90-day production period. Unless the operator receives a determination from a jurisdictional agency that the increase was due to the application of recognized enhanced recovery techniques, or is determined to be seasonably affected, he may no longer collect the stripper price for the well. If the operator files a petition for a determination that the increase in production results from enhanced recovery techniques or seasonal fluctuation, continued, collection of the stripper well price shall be made subject to refund for deliveries made after the last day of the applicable 90-day or 12-month production period.

Part 271—Subpart I

Subpart I of Part 271 implements section 109 of the NGPA by setting a maximum lawful price for "other categories of natural gas," that is, for first sales of natural gas that are *not covered by any maximum lawful price under any other subpart of Part 271.* (emphasis supplied)

Section 109 of the NGPA presents an important question of interpretation. The portion of section 109(a) which precedes paragraph (1) limits section 109's application to "natural gas which is *not covered by any maximum lawful price under any other section of this subtitle.*" [emphasis supplied] However, paragraph (1) of section 109(a) specifically includes natural gas "produced from any new well *not otherwise qualifying for a higher maximum lawful price.*" (emphasis supplied) The question presented is whether the general language in section 109(a) is intended to limit the scope of the examples which follow (so that new wells which qualified for a lower price under another section of the NGPA would be excluded from section 109), or whether the specific examples override the general statement of the scope of section 109 (so that new wells otherwise subject to a maximum lawful price which is lower than the 109 price nonetheless be eligible for the higher 109 price.

In this regard, it should be noted that the portion of section 109(a) which precedes paragraphs (1) through (4) introduces those paragraphs with the word "including." Under general rules of construction therefore it would appear that paragraphs (1) through (4) are qualified and controlled by the general statement of applicability which limits 109 to first sales *not covered* by any maximum lawful price. For this reason, the Commission is tentatively of the view that the first interpretation is correct and has incorporated that interpretation in the regulations implementing Section 109. A special rule in § 271.904 provides that the maximum lawful price in this subpart applies to a first sale of natural gas described in paragraph (1), (2), (3), or (4) of section 109(a) only if that first sale is not

covered by any other maximum lawful price in the NGPA.

As noted above, the Commission is aware that section 109 is susceptible to an interpretation different from the one proposed in the special rule. Comments on the approach taken and suggested alternatives are specifically requested.

Part 271—Subpart K

Subpart K of Part 271 of the Commission's proposed regulations implements section 110 of the NGPA. That section permits a first sale price of natural gas to exceed the applicable maximum lawful price for that sale to the extent necessary to recover State severance taxes borne by the seller. It also permits the same treatment for certain production-related costs borne by the seller, if allowed by the Commission.

The treatment to be accorded the addition of State severance taxes to maximum lawful prices is set forth under § 271.1102. The definition of "State severance tax" in § 271.1101 is the definition set forth in the Act. Paragraph (b) of § 271.1101 precludes recovery of those severance taxes which were enacted on or after December 1, 1977, and which do not apply equally to natural gas produced for delivery to interstate commerce and gas produced but not so delivered.

Paragraph (b) of § 271.1102 acknowledges that the just and reasonable rates applicable to natural gas produced from the Permian Basin area included a specific allotment for State severance taxes and excludes those amounts from the provisions of the section.

The section contains a requirement that sellers retain records of transactions in which the maximum lawful price is exceeded as a result of the addition of severance taxes.

The treatment of production-related costs is set forth in § 271.1104. This section establishes a procedure under which the Commission will consider applications for addition to maximum lawful prices only for those production-related costs specified in this section.

Paragraph (b) of the section precludes the filing of any application under this section with respect to natural gas which, as of November 8, 1978, was committed or dedicated to interstate commerce and was subject to a just and reasonable rate in effect at that time. It also precludes applications with respect to natural gas subject to an existing contract, or successor to an existing contract, or a rollover contract.

The proposal provides, in paragraph (c), that applications to the Commission will be considered for costs of gathering, liquifaction or transportation only if those activities occur off-lease. This paragraph also provides that the Commission will consider applications for costs of compression.

Paragraph (d) sets out certain quality standards for natural gas. Only applications covering costs to bring gas to a quality greater than that specified in the standards in the paragraph will be considered under this paragraph. It also provides an exception to this rule for transactions involving sales to end users.

Section 271.1100(b) excludes from the operation of both § 271.1104 and § 271.1105 relating to production-related costs, natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the system approved under the Alaska Natural Gas Transportation Act of 1976 (ANGTA). Prudhoe Bay is a new and unique producing area for which there is no history of industry practice relative to the bearing of production-related costs. Therefore a separate rule under the provisions of ANGTA for natural gas from that producing area is required and will be promulgated by the Commission in the immediate future.

Part 273

The purpose of Part 273 is the establishment of procedures for the interm collections authorized by section 503(e) of the NGPA. That section permits interim collection, subject to refund, of those prices for certain categories of natural gas which must be authorized by a determination of well eligibility to be made by the jurisdictional state or federal agency and then reviewed by the Commission. These categories are new gas and certain OCS gas (as defined in section 102 of the NGPA), gas from new onshore production wells (section 103) high-cost natural gas (section 107) and stripper well gas (section 108).

Description of the regulations. Part 273 is divided into three subparts covering

general provisions, the four separate provisions for interim and retroactive collections, and the procedures for refund guarantees and refund payments. Section 273.101 states that general authorization under these regulations to collect a maximum lawful price for a particular category of gas does not give a seller the right to collect a price which is higher than that permitted by the sales contract. Section 273.102 defines a "final determination" for purposes of this part as a determination of eligibility by the jurisdictional state or federal agency which is no longer subject to the possibility of review and reversal by the Commission or the courts. It should be noted that under section 503(d)(1) of the NGPA a determination which has already become final can be reviewed and modified later if it was based in part on a factual statement which was untrue or materially misleading. Section 273.103 requires each seller to file an annual report of any collections and refunds under this part. Prior to the end of the first reporting period, on December 31, 1978, the Commission will issue a further rule specifying the form and scope of this report.

Subpart B of Part 273 provides the specific rules for interim collections and for retroactive collections where the maximum lawful price established by a final determination exceeds the price collected on an interim basis. Section 273.201 establishes a transitional rule for sales from new wells. It will expire on March 1, 1979. A seller may collect, subject to refund, the price specified in section 109 of the NGPA if an application for determination will be submitted to the jurisdictional agency by March 1, 1979. A seller may charge and collect the price determined under section 109 of the NGA and specified in paragraph (a) of § 273.201 ($1.630 per MMBtu for December 1978) after complying with the filing requirements of this section and until March 1, 1979. To qualify for this collection authority, a seller must file with the Commission sworn statements that the sale is being made from a new well and is eligible for the price to be collected and that the seller has filed an application for determination with the jurisdictional agency or will do so by March 1, 1979.

After that application for determination has been filed, a seller may use the procedure established by § 273.202 to collect, subject to refund, the maximum lawful price for which the sale is believed to be eligible, for a period of up to eighteen months (or twelve months where collections under the section begin on or after May 1, 1979). To qualify for this interim collection authority, a seller must fulfill certain filing requirements, by submitting a sworn statement of eligibility, a duplicate of the NGPA form on which the application for determination has been submitted, and a statement certifying that a portion of the amounts collected under this procedure will be placed in escrow or secured by surety bond.

The authorization to make interim collections of the price for which the sale is believed to be eligible terminates on the date on which the Commission receives a notice that a determination of eligibility has been made or after eighteen months (or twelve months where collections under the section begin on or after May 1, 1979) where no determination has been made. After such termination, the seller may not use this procedure again for this sale or any other sales from the same well. The seller will be limited to collection of the applicable maximum lawful price specified in Subparts D, E, F, or I of Part 271 until an initial determination is made, and § 273.203 can be used to collect the price established by that determination.

When the jurisdictional agency issues its determination of eligibility for the well from which the sale is being made, § 273.203 authorizes interim collection, subject to refund, of the price established by that initial determination. Within 15 days after interim collections begin under this section, a notice of collections must be filed with the Commission and served upon the purchasers. There are no other filing requirements under this section. The authority to collect the price established by the initial determination of eligibility ends 15 days after that determination has been reviewed and becomes final. If the Commission does not approve or reverse an initial determination, but makes a final finding that the determination should be remanded to the state or federal agency for further consideration, then the seller may continue to collect the price established by the remanded determination for up to six months during reconsideration by the jurisdictional agency.

When a determination of well eligibility becomes final, a seller may immediately collect the price established there for all future sales from that well under the authority of the applicable section of Title I of the NGPA and Part 271 of these regulations. Section 273.204 of this part authorizes the retroactive collection of that finally-determined price for all first sales of gas delivered after the application for determination was filed. If this application is filed by March 1, 1979, then retroactive collections may be made for gas delivered on or after December 1, 1978. There are several qualifying conditions. A seller may not make retroactive collections for any first sale if the seller has not fully complied with all of the filing requirements and other provisions of these regulations for every first sale made by that seller. Similarly, a seller may not collect a retroactive amount from each purchaser for any sale until the seller has refunded to that purchaser all amounts which are then due to be refunded for the same sale or any other sale.

In some instances, the provisions of this part will be used to collect interim prices for first sales of natural gas which was committed or dedicated to interstate commerce on November 8, 1978, the day before the date of enactment of the NGPA. Under section 601(a)(1) (B) of the NGPA, sales of committed or dedicated gas will be subject to the Commission's jurisdiction under the Natural Gas Act, particularly to the filing requirements for making a rate change, until a final determination that such gas qualifies as high-cost gas, new gas, or gas produced from a new onshore production well. The relationship between the filing requirements of these NGPA regulations and Part 154 of the regulations under the Natural Gas Act will be discussed in the Commission's final rule amending § 154.94(h) of Part 154 to be issued shortly in Docket No. RM79-4. Under the final rule, in the case of interim collections for first sales of gas which remain subject to the requirements of the Natural Gas Act, full compliance with the filing requirements of this part of the regulations under the NGPA will also satisfy the additional filing requirements under section 4(e) of the Natural Gas Act and Part 154 of the Commission's regulations. Thus, a seller which makes the filing required by § 273.203(c) may collect the price specified in the application for determination of eligibility without submitting the prior notice of rate change required by § 154.94 of the Commission's regulations under the Natural Gas Act.

Subpart C of this part establishes procedures to assure that any interim collections will be refunded as necessary and for the actual payment of refunds with interest after a final determination that a first sale does not qualify for a price already collected under this part. Section 273.301 establishes a general obligation upon each seller to refund any collections which are not authorized by the NGPA and these regulations, if ordered to do so by the Commission at any time. For example, a determination can be reconsidered and modified after it becomes final, if it was based on an untrue or materially misleading statement of facts in the application for determination. As a result of that modification, additional refunds could be ordered even though the seller would have already discharged any specific refund obligations under § 273.302 and the prior final determination.

Section 273.302 sets out specific procedures for refund assurance and payment. A seller's potential liability to refund any interim collections must first be secured by the filing of a written undertaking to make refunds using one of the forms set out in § 273.302(b). A seller must file a series of refund undertakings covering collections for sales from the wells identified in an appendix to each successive undertaking or one blanket undertaking which is a general agreement to make all refunds which may be required under the NGPA.

Interim collections that are made under § 273.202 pending an initial determination of eligibility and the proper price are subject to an additional requirement providing refund assurance. The seller is further required to secure surety bonds or to place in escrow the portion of the price collected under § 273.202 which exceeds the maximum lawful price determined under Section 109 of the NGPA (for sales from new wells) or the maximum lawful price under Sections 104, 105 or 106 of the NGPA (for sales from old wells).

Other provisions of § 273.302 require each seller to maintain full records of the amounts that are collected, subject to

refund, and to make the actual refunds by cash or check within fifteen days after the applicable determination of eligibility becomes final. There is no provision for any other method to discharge a refund obligation, such as by work-offs, commitment of additional reserves to each purchaser, or reduction of the price charged for future deliveries. Permission to use an alternative refund method will be granted only in exceptional cases.

Parts 274 and 275

General. Under certain sections of the NGPA, eligibility for the maximum lawful price established by the Act is initially determined by the state and federal agency with regulatory jurisdiction over the production of natural gas. Jurisdictional agencies' determinations are subject to review by the Commission.

Jurisdictional agencies are authorized to make the determinations with respect to:

(1) new natural gas under section 102(c) of the NGPA;

(2) certain gas from the OCS under section 102(d);

(3) new onshore production, defined in section 103(c);

(4) high-cost natural gas defined in section 107(c); and

(5) stripper well natural gas defined in section 108(b).

The purpose of Subparts B, C, G, and H, of Part 271, is to reflect the statutory criteria for qualification for the maximum lawful prices for the categories of gas noted above and to propose rules necessary to clarify or implement those provisions. Subpart B of Part 274 of the proposal contains the filing requirements the Commission proposes to apply to applications for determinations filed with jurisdictional agencies. Other sections of the proposal apply to the procedures by which jurisdictional agencies make initial determinations and give notice of determinations to the Commission (Part 274, Subpart A) and the method by which the Commission will review those determinations (Part 275, Subpart B). Each of these provisions is summarized below.

Part 274—Subpart A

Subpart A of Part 274 prescribes procedures by which jurisdictional agencies make determinations pursuant to and in accordance with the NGPA. This subpart provides that the procedures to be applied are those followed by the agency to make comparable determinations. In addition, this subpart contains a rule concerning the manner in which a jurisdictional agency must notify the Commission that it has made a final determination of eligibility.

Section 274.102 provides that a determination is made once it is "administratively final" before the jurisdictional agency. If, for example, a state agency's decisions are normally subject to rehearing under its usual procedures, the determination is not final until the period for rehearing expires or rehearing is sought and denied.

Section 274.104 provides that a jurisdictional agency must notify the Commission within 15 days after making a determination and prescribes the manner in which the jurisdictional agency shall give the notice. Section 274.105 provides an option to the procedures prescribed in § 274.104. If an agency chooses to adopt the § 274.105 option, it may file with the Commission a report in which it undertakes to make the necessary determinations and which includes a description of the procedures which it would follow in making them. The jurisdictional agency would then be relieved of the obligation to describe its procedures in each case. The public, and more especially representatives of the various agencies involved, are invited to suggest revisions or alternatives to this subpart which would both preserve state procedures and provide the Commission with an adequate basis for fulfilling its review responsibilities.

Part 274—Subpart B

Subpart B of Part 274 prescribes the filing requirements which must be met by an applicant to obtain a determination for new natural gas from a jurisdictional agency.

Section 274.201 sets forth general rules applicable to all applications. Succeeding sections impose specific requirements depending on the nature of the determination sought. The general requirements include a provision that applicants give notice of applications to their purchasers. Jurisdictional agencies may prescribe additional filing requirements.

Section 274.202 sets forth filing requirements for a determination that gas qualifies as new natural gas under section 102 of the NGPA. The regulations require an applicant to present evidence substantiating, to the extent practicable, each element of proof required for a determination of eligibility. Section 274.202(c)(1) is typical of other sections in this subpart in that the applicant must file certain specific documents as well as the oath statements. Each applicant filing for a new onshore well determination under § 274.202(c)(1), must file a location plat showing all wells within 2.5 miles of his own well. He must then demonstrate that none of these wells is a marker well. In order to meet this burden, an applicant must consult all available records which would indicate whether any of these wells produced in commercial quantities at any time during the period from January 1, 1970 to April 20, 1977. Rather than require an applicant to file all production records along with the application, however, the proposal requires the filing of a statement, under oath, describing his search of records, and attesting to the fact that none of these wells is a marker well. The applicant's description of his search of records will enable jurisdictional agencies to verify the applicant's conclusion. This regulation is similar to the others which impose filing requirements. It attempts to strike a balance between the need to support each determination by substantial evidence and the potential for excessive burdens on applicants and jurisdictional agencies.

Applicants filing under § 274.202(d) for a new onshore reservoir determination must submit geological information which demonstrates that production is from a new onshore reservoir. These data are accompanied by an attestation similar to that required by paragraph (c). In all cases individual agencies may, if they wish, require the filings of all documents relied upon by the applicant. The Commission has taken a similar approach toward filing requirements under § 274.203.

Section 274.206 prescribes the filing requirements for applications for stripper well determinations. To a greater extent than other sections of this subpart, this section requires the submission of actual documents rather than oath statements. In addition to the documents, applicants must submit an affidavit attesting to the well's eligibility.

Section 274.207 entitled "Alternative filing requirements," acknowledges that due to differences in State records, some jurisdictional agencies may desire or need to resort to documents other than those required by these proposed regulations. Under this section, a state agency may propose alternate filing requirements which might replace some or all of the requirements specifically provided elsewhere in Subpart B. If the Commission concludes that the alternative requirements are more appropriate for a particular state and will satisfy the evidentiary requirement it may approve the alternative requirements. Upon such approval, applicants for determinations would file according to the alternate plan rather than under Subpart B.

The Commission wishes to emphasize the need for public comment on this subpart. It is essential that filing requirements be practical and manageable from the standpoint of both the applicants and the jurisdictional agencies. It is also essential, however, that they provide the jurisdictional agencies and the Commission with substantial evidence on which to make and review determinations.

Part 274—Subpart C

Subpart C of Part 274 briefly prescribes the procedures by which a jurisdictional agency may execute an agreement to waive its authority to make NGPA determinations. It implements section 103(c)(2) of the NGPA.

In order for a jurisdictional agency to waive its authority, it must enter into an agreement with the Commission. Under § 274.302, an agency may submit a request for waiver to the Commission. Section 274.303, specifies the contents of such a request and requires an agency to state the reasons and the necessity for a waiver. If the Commission agrees to enter an agreement of waiver, it may do so on terms and conditions agreed to by the Commission and the jurisdictional agency. The provisions of § 274.303 specify the method of terminating the waiver agreement by either the Commission or the jurisdictional agency. Section 274.302 provides that the Commission shall give public notice of all agreements of waiver and that once a waiver agreement is executed, applicants should file

for determinations with the Commission according to the filing requirements set forth in Subpart B of Part 274.

Part 275—Subpart B

Subpart B of Part 275 prescribes the procedures governing Commission review of determinations by jurisdictional agencies. The regulations are promulgated under the provisions of section 503 of the NGPA and the general rulemaking authority of section 501(a) of the Act.

Section 275.201 provides that upon receipt of the notice of determination from a jurisdictional agency, the Commission will give public notice of the determination in the Federal Register. In addition to identifying the specific proceeding, the notice will indicate that the record of the proceeding is available for inspection in the Commission's Office of Public Information.

Subparagraph (a)(1) of § 275.202 tracks section 503(b)(1) and (2) of the statute in setting forth the standards which govern Commission review. The Commission will reverse decisions not supported by substantial evidence and will remand decisions to the jurisdictional agency if there is evidence in the Commission's records which was not before the jurisdictional agency and which is inconsistent with the determination. Section 275.202(b) also contains procedures under which the Commission will return determinations to jurisdictional agencies based on applications which did not comply with applicable filing requirements. Unless a conforming application to the jurisdictional agency is made within 45 days, the applicant's right to any interim collection of the requested rate terminates.

Under § 275.203 any person may file a protest with the Commission within 15 days after the Commission publishes notice of receipt of a determination by a jurisdictional agency. Any person protesting a determination must indicate whether it is alleged that the determination is not supported by substantial evidence or that there is inconsistent information in the Commission's files. It should be noted that under § 275.203(b)(iii), a protestor may submit information for inclusion in the Commission's public records. Accordingly, the data or information on which the Commission may rely in remanding a determination need not have been in the Commission's records at the time the jurisdictional agency made the determination.

Section 275.202(d) provides for conferences with the Commission staff after issuance of a preliminary finding. While the NGPA does not require such a procedure, the Commission wishes to provide an opportunity to all parties, including jurisdictional agencies, to present views concerning a determination. In addition, the conference procedure will assist the Commission in making a judgment on review.

Section 275.202(e), consistent with sections 503(b)(1)(B), and (b)(2)(B) provides that the Commission will issue a final order within 120 days after issuance of a preliminary finding. While the statute requires a final order only when the Commission wishes to reverse or remand a decision, the proposal provides that the Commission will issue such an order in any case in which a protest was filed and a preliminary reversal or remand was issued.

Under section 503(d), final determinations are binding unless based on an untrue statement of fact, or a record from which a statement of material fact was omitted. Section 275.205 of the proposal sets forth a procedure for reopening determinations on those grounds. The Commission may, at any time, on its own motion or in response to a petition, reopen a determination if it appears that the necessary grounds exist.

If the Commission does reopen a determination, it will give notice to the jurisdictional agency involved as well as to all persons who participated in the prior proceeding. Within 150 days of the Commission order reopening a determination the Commission will issue a final order after giving all persons who received notice an opportunity to express their views. If the Commission finds that the requisite grounds exist, it will vacate the determination and order remedies, including refunds, as it deems appropriate.

In conjunction with the substantive rules and the regulations concerning filing requirements, this subpart should provide an adequate basis for the exercise of review authority. In addition, this subpart is intended to open the review procedure to all interested persons to the

extent possible within the time constraints imposed by the statute. The proposals in this subpart should be considered with these purposes in mind. The Commission is particularly interested in comments on this subpart.

Part 276—Subpart A

Subpart A of Part 276 sets forth reporting requirements applicable to first sales of natural gas sold under existing intrastate contracts, intrastate rollover contracts, and other categories of natural gas (Subparts E, F and I of Part 271).

In each case, certain information is required of the seller. If the purchaser of gas under section 105 or 106 of the NGPA is a pipeline, the purchaser must also file reports. Finally, in some instances, sellers of less than 10,000 MMcf of natural gas per year may elect to make oath filings instead of detailed reports.

A seller of natural gas under an existing intrastate contract must file annually a report setting forth detailed contract information as well as an oath filing that the information in the report is true, and that sales in the reporting period comply with the NGPA and Subpart E of Part 271. Successive annual reports need not restate previously reported information.

If the sale is to an interstate or intrastate pipeline, the pipeline, rather than the seller, is responsible for filing the detailed contract information, as well as an oath statement as to the accuracy of the information. If a pipeline purchaser makes the principal filing, the seller must still file a statement under oath that the sale complies with the NGPA and Subpart E of Part 271, and that the seller undertakes to retain records reflecting the detailed information.

Reports required with respect to sales under intrastate rollover contracts are essentially the same as for sales under existing intrastate contracts, with appropriate modifications, and are set forth in § 276.103.

The annual reports with respect to sales under Subpart I of Part 271 are set forth in § 276.104. This report, filed by the seller, is required to provide detailed information with respect to the sale and an oath statement that the gas does not qualify under any subpart of Part 271 which provides a maximum lawful price lower than that under Subpart I, and that if the gas was committed or dedicated to interstate commerce a notice of rate change has been filed pursuant to § 154.94. The oath filing must also contain a statement regarding compliance with the NGPA and Subpart I and the truth of the information.

Sellers who sell less than 10,000 MMcf per year may elect reduced reporting requirements with respect to sales to purchasers other than pipelines under Subparts E and F. These sellers may file, instead of detailed information otherwise required an oath statement as to compliance with the NGPA and applicable regulations and as to an undertaking to retain books and records containing the requisite information.

Part 284

Part 284 implements sections 311 and 312 of the NGPA in four subparts. Subpart A (section 311(a)) covers transportation of natural gas by interstate pipelines. Subpart B (section 311(a)) covers transportation by intrastate pipelines. Subpart C (section 311(b)) is proposed to become effective to cover sales by intrastate pipelines occurring after this winter heating season. A modification of the Commission's existing 60-day emergency transaction rules is proposed for implementation on December 1. Subpart D (section 312) provides for the assignment by intrastate pipelines of the contractual right to receive surplus natural gas.

Part 284—Subpart A

Subpart A provides that interstate pipelines may without prior Commission approval transport gas on behalf of intrastate pipelines and local distribution companies. The rates must be just and reasonable. If the interstate pipeline has on file a rate schedule applicable to these transactions, it must use the rates contained therein. Otherwise, it may charge either (1) a rate based on the methodology for recovering the transmission component of its sales rates, or (2) a rate for comparable service under its transportation rate schedule. Revenues in excess of 1 cent per Mcf must be credited and flowed back except to the extent the revenues (or volumes) have already been taken into account for rate purposes.

Contracts must be conditioned upon available capacity and compliance with

the regulations. The maximum duration is two years, with rights to apply for extensions for additional two-year periods.

Reports required are the initial report (30 days after service begins), a subsequent report whenever information in the initial report requires updating; an extension report (90 days before extension) and a final report (30 days after termination).

Part 284—Subpart B

Subpart B provides for transportation of natural gas without prior Commission approval by intrastate pipelines on behalf of interstate pipelines and local distribution companies served by interstate pipelines. Rates are required to be fair and equitable. An intrastate pipeline may charge either (1) a rate based on methodology for recovering the transmission component of its effective sales rates, or (2) a rate contained in a transportation schedule for comparable service.

Transportation arrangements and extensions (permitted unless disapproved by the Commission) may not exceed two years. The Commission may impose appropriate terms and conditions. Reporting requirements are similar to those in Subpart A.

Part 284—Subpart C

Subpart C is proposed to implement section 311(b) of the NGPA which, when adopted after this winter, will among other things, replace the emergency transaction exemptions. The proposal in its present form would authorize sales by intrastate pipelines to interstate pipelines and local distribution companies without prior Commission approval, but such sales could be terminated upon complaint or the Commission's own motion if the Commission made certain determinations set forth in the NGPA. Rates would be required to be fair and equitable, providing reasonable compensation for services and a reasonable opportunity for profit, plus an adjustment for current costs incurred under prescribed circumstances due to the sale, in addition to the pipeline's current weighted average acquisition cost of gas.

The adjustment would be permitted for natural gas included in a sale by an intrastate pipeline if the gas is acquired under an existing contract, is in excess of volumes that the pipeline would acquire but for the sale, and is priced above the pipeline's current weighted average cost of natural gas. In this case, the price of gas in a sale pursuant to Subpart C would be adjusted upward so as to offset the increase that would otherwise occur in the weighted average acquisition cost of gas. The purpose of the adjustment is to remove any incentive for the intrastate pipeline to defer purchases of gas otherwise available to it while preventing an increase in the cost of gas supplied to the intrastate customers. An example of calculation of an adjustment follows in Table A.

Table A—Sample Calculation of Adjustment

1. Intrastate pipeline purchased 800,000 Mcf during most recent actual 12-month period at a total cost of $1.5 million for a weighted average cost of $1.88 per Mcf.

2. At the time that the sale was being negotiated the lower cost source of supply had escalated so that the total cost of gas was $1.6 million or $2.00 per Mcf.

3. Intrastate pipeline could make available on an interruptible basis up to 100,000 Mcf annually which would be purchased under a contract providing for a price of $2.00 per Mcf in which case there would be no adjustment to the average cost of gas.

4. Alternatively, interruptible volumes of up to 100,000 Mcf annually would be available at a price of $2.50 per Mcf. In this case it would be necessary to charge a $2.50 rate in order not to affect the cost of gas to the regular customers of the pipeline.

Base Period		
Mcf	Price	Cost
100,000	× 1.00 =	100,000
200,000	× 1.50 =	300,000
300,000	× 2.00 =	600,000
200,000	× 2.50 =	500,000
800,000	× 1.88 =	1,500,000

Current Period		
Mcf	Price	Cost
100,000	× 2.00 =	200,000
200,000	× 1.50 =	300,000
300,000	× 2.00 =	600,000
200,000	× 2.50 =	500,000
800,000	× 2.00 =	1,600,000

Current Period Adjusted for Add. Sales

Assume Purchase @ $2.00

Mcf	Price	Cost
100,000	× 2.00 =	200,000
200,000	× 1.50 =	300,000
400,000	× 2.00 =	800,000
200,000	× 2.50 =	500,000
900,000	× 2.00 =	1,800,000

1,850,000
−1,800,000
50,000 + 100,000 Mcf = $.50

Assume Purchase @ $2.50

Mcf	Price	Cost
100,000	× 2.00 =	200,000
200,000	× 1.50 =	300,000
300,000	× 2.00 =	600,000
300,000	× 2.50 =	750,000
900,000	× 2.00 =	1,850,000

Average cost of gas = $2.00
Adjustment + .50
Total = $2.50

Sales would be subject to interruption if necessary for adequate service to the intrastate pipeline's other customers. Other terms and conditions could be imposed.

The proposed Subpart C is included in the Notice of Proposed Rulemaking to be issued simultaneously with these interim regulations, but is proposed to be adopted after this winter heating season so a smooth transition may be accomplished between implementation of the emergency exemption provisions of §7(c) of the Natural Gas Act and implementation of section 312 of the NGPA. A revised version of the Commission's current emergency program, terminating Docket No. RM78-7 will be adopted to be effective this winter only. The interim rule for emergency transactions is discussed below.

Part 284—Subpart D

Subpart D implements section 312 of the NGPA, and requires prior Commission approval for certain assignments of an intrastate pipeline's contractual right to receive surplus gas. Assignments would be authorized only if the Commission determined them to be consistent with Subpart D and the NGPA, and necessary or appropriate in the public interest. An exception to the prior approval rule would cover assignments of rights to receive gas if it were priced at or below the new gas price. These would be self-executing, subject to terms and conditions imposed by the Commission, and to certain reporting requirements. If an assignment is authorized, any intrastate pipeline could assign all or any portion of its contractual right to receive surplus natural gas to an interstate pipeline or local distribution company. The intrastate pipeline would have to furnish documentation of a determination by the state regulatory agency having jurisdiction over it that the gas involved was surplus.

Emergency Sale Exemptions

Background

On April 7, 1978, the Commission issued a Request for Comments regarding its proposed review of the 60-day emergency provisions for the sale and transportation of natural gas in interstate commerce. Comments were received from parties representing a wide range of interests, including independent and associated producers, intrastate and interstate pipelines, distribution companies, industrial consumers and the public.

After the comments were reviewed and analyzed the Commission issued a Notice of Proposed Rulemaking on August 14, 1978, and again requested comments. The proposal would have substantially changed the existing regulations covering emergency transactions.

Summary of the Proposal

The existing regulations, 18 C.F.R. §§2.68, 157.22 and 157.29, create exemptions from the certificate requirements of section 7 of the Natural Gas Act for the transportation and sale of natural gas in interstate commerce. Under these provisions emergency supplies of natural gas were obtained in substantial quantities in past winter heating periods and during times of summer storage fill, at market prices in excess of otherwise applicable national or area rates governing jurisdictional sales. The existing regulations allow a pipeline to buy emergency gas for 60-day periods whenever lack of supplies forces it to curtail its service to any customer. Each pipeline has the option of either injecting the emergency gas into its general system supply and recovering the costs through the purchased gas adjustment accounts, or specifically assigning the supplies to the customers in need of them and charging

those customers for the cost of the volumes they receive.

The proposal also would have allowed exemptions from the certificate requirements but would have imposed stricter criteria for participation in the transactions. Emergency supplies would have been made available only for certain high priority end users, not including large industrials which have alternate fuel facilities and alternate fuels available during severe supply emergencies. The sales would have been allowed for 60 days only, without any extensions except under certain limited circumstances.

Pipelines would have been allowed to inject emergency gas into their system supply only when force majeure-type emergencies existed or for summer storage injection. Otherwise, the gas and its costs would have had to be directly assigned to the customer who requested it.

The proposal would have placed a restrictive standard on rates for emergency sales and transportation. Most importantly a rebuttable presumption of prudence was accorded only to producer sales in cases where the price was less than or equal to the current intrastate producer's sales of comparable location contract vintage as reported in FPC Form 45 and where the price was the lowest offer obtained as a result of inquiries with at least three qualified sellers.

The proposal also required additional reporting requirements to allow the Commission to monitor activities of emergency purchasers and sellers and to reduce the number of unnecessary emergency transactions.

Basis of this Amendment

The enactment of the NGPA on November 9, 1978, changed much of the statutory authority on which the proposed emergency transaction exemptions were based. Title I of the Act establishes first sale price controls for interstate and intrastate natural gas. No longer are certificates required for new producer sales to the interstate market. Section 311 of the NGPA authorizes the Commission to allow intrastate pipelines to transport interstate gas without a certificate and allows interstate pipelines to transport gas on behalf of intrastate pipelines and local distribution companies. This authority has been implemented in Part 284 of the regulations. As a result, in large part, producer sales and pipeline transportation of intrastate gas in interstate commerce no longer require exemptions from the certificate requirements of the NGA.

Sales by an intrastate pipeline to interstate pipelines may be authorized pursuant to the authority vested in the Commission by the NGPA subject to certain statutory conditions and requirements. Because such transactions are not first sales under Title I of the NGPA, intrastate pipeline sales would continue to be governed under the NGA unless and until the Commission exercises its authority under Section 311(b) of the NGPA.

Inasmuch as the winter heating season is already upon us and in light of the potential for confusion and complication as would result from any attempt to implement for immediate application the section 311(b) authority, the Commission has determined to bring to conclusion its pending rulemaking and issue a rule which will largely leave the current emergency program in place for this winter. We therefore propose to notice for comment a proposed regulation implementing 311(b) but have suggested an effective date of March 31, 1979—the conclusion of the current winter heating period.

Thus amendments to the existing regulations relating to emergency sales will terminate Docket No. RM78-7. This rule continues the 60-day emergency sales program, as modified, for this winter heating season and will eventually be replaced by regulations implementing the Commission's authority over sales under section 311(b) of the NGPA. The 60-day emergency program is temporarily implemented to permit a smooth transition from existing regulatory provisions to the regulations to be adopted pursuant to NGPA.

Comments

The comments received in Docket No. RM78-7, relating to producer sales, ceiling prices and pipeline transportation will not be discussed here. These issues have been resolved by the passage of the NGPA. Accordingly, our discussion is focused on those comments and issues which remain relevant to this rulemaking including the definition of regulation of emergency; purchaser qualifications; methods of insuring complaince with the

regulations; the duration of the transactions; price ceilings; reporting requirements; and the effective date of this rule.

The definition of emergency, in the proposal, required pipelines to focus on actual needs of end users rather than on the pipeline's curtailment. Many of the comments opposed such criteria. Because this rule is temporary only, and intended to operate during a transition period, the Commission has determined to adopt a definition of emergency that includes curtailment on a pipeline's system, a sudden unanticipated loss of supply or a situation where emergency gas is needed to protect life, health or physical property.

Purchaser qualification, in the proposal, allowed only distribution companies or interstate pipelines to purchase emergency supplies. Several of the commentators felt that qualified purchasers should be expanded to include direct industrials and all persons exempt from the provisions of the Natural Gas Act pursuant to section 1(c). The final rule does not enlarge the category of qualified purchasers. This rule will apply this winter only. The Commission points out, however, that the final rule like the proposal does permit direct assignment of emergency gas to industrial needs.

The methods of insuring compliance with the regulation caused concern among many of the commentators. Many felt that compliance with many of the requirements was beyond the control of each participant and that participants should be responsible only for those conditions which they could control. The Commission's intent behind insuring compliance is limited to guaranteeing that each participant fulfill the requirements applicable to his or her participation. Participants are responsible for the actions of other participants only to the extent explicitly described in the regulation.

The proposed duration of the transactions, which were limited to sixty days with extensions, did not draw significant comments. The Commission will adopt the 60-day limitation with extensions, as proposed.

The price ceilings aroused much concern among producers but no longer apply to them. Intrastate pipelines stated they should be allowed to charge all replacement costs rather than be limited to the weighted average system-wide costs with adjustments.

The reporting requirements were generally accepted. Some commentators stated that the requirements were unreasonably burdensome. Only two reports, however, are required. One is simply a notification with information which may be briefly stated. The other requires more extensive information which should be readily available. Both requirements are necessary for the Commission to monitor emergency transactions.

Summary of the Emergency Exemptions Made Effective by this Rule

The emergency exemption rule deletes §§2.68, 157.22 and 157.29 from the regulations, and applies to emergency sales of gas by "qualified sellers," defined as any intrastate pipeline, interstate pipeline or local distribution company. "Qualified purchasers" are interstate pipelines and local distribution companies. Emergency sales are exempted from the certificate requirements of section 7 of the NGA so long as they meet the requirements of the emergency sale regulations.

Emergency supplies may be purchased only in cases of an emergency as defined in the regulations. Emergency transactions may not last more than 60 consecutive days unless the qualified purchaser has filed a petition requesting waiver for another 60 days and the Commission has not denied the petition. Emergency supplies may be injected into system supply or directly assigned to a pipeline customer. Sales by interstate pipelines shall be made at rates prescribed in their tariffs. Sales by intrastate pipelines and distribution companies will be rebuttably presumed to be prudent if they do not exceed the maximum lawful price for new gas under §271.202. Revenues in excess of 1 cent per Mcf must be credited and flowed back except to the extent the revenues (or volumes) have already been taken into account for rate purposes.

The interstate pipeline shall notify the Commission of any deliveries of emergency gas within 48 hours after commencement of the deliveries. They shall also submit reports each period in which emergency gas is delivered which will provide the Commission more extensive information.

Effective Date

The effective date of this rule is December 1, 1978. For the reasons stated with respect to the interim rules under the Natural Gas Policy Act of 1978, and because we are already in the midst of the winter heating season the Commission finds that good cause exists to waive publication of these amendments thirty days prior to their effective date.

III. Public Procedure

Although the NGPA was not enacted until November 9, 1978, most of its provisions become effective on December 1, 1978. On that date, persons affected by the Act, including a large portion of the natural gas industry not previously regulated by the Federal government, will be subject to a comprehensive and complex new regulatory structure. For reasons set out more fully below, regulations implementing the Act must be effective on December 1, 1978, both for guidance to those regulated and to insure compliance with the new law.

When it became apparent that the period between final enactment of the law and its effective date would not provide sufficient time for the normal rulemaking procedures, the Commission established the following schedule and procedures.

The Commission has been meeting in public session since November 1, 1978, in order to discuss regulations drafted by the staff to implement the NGPA. Prior to the first meeting, the Commission made copies of the various proposals under consideration available to the public. As successive drafts were completed, these too were released prior to Commission discussion. During all of this period, certain members of the Commission staff were publicly designated as contact persons to answer legal and technical questions concerning the implementation of the Act.

The Commission intends to promulgate interim regulations on November 27, 1978. The interim regulations will be effective on December 1. A 60-day comment period will be afforded with respect to the interim regulations and public hearings will be held. The interim regulations will, after the 60-day period and after all views received since November 1, 1978, have been considered, be modified to the extent such comments and the Commission's experience under the interim regulations indicate that modification is appropriate.

The proposal published today provides for a comment period ending on November 20. The Commission is aware that in view of the significance and complexity of these regulations, comments will be extensive. To the extent possible, comments received before November 20 will be reviewed and appropriate changes incorporated into the interim regulations. As stated above, all comments will be retained and considered together with the additional comments received during the 60-day period afforded for comments on the interim regulations. The Commission believes that to the extent practicable, the procedures being followed with respect to these regulations are those best designed to insure maximum public participation prior to the time when the interim regulations must be effective.

In establishing this notice and comment procedure, the Commission has considered a number of factors. Most important, as stated above, is the fact that most of the Act's provisions become effective on December 1, 1978, including provisions establishing maximum lawful prices applicable to first sales of natural gas delivered after November 30, 1978. Some of the prices which may be charged for natural gas deliveries under the Act are established by reference to existing prices. For other categories, pricing determinations must be made by State or Federal agencies with regulatory authority over the production of natural gas. Unless the interim regulations are available on December 1, 1978, members of the public whose sales are governed by provisions of the Act will not be able to ascertain the applicable maximum lawful price governing their sales of natural gas. Indeed, some sellers and transporters of natural gas could unknowingly be in technical violation of the law. Purchasers may be uncertain whether prices requested exceed the prices permitted under the law. Similarly, agencies which must make determinations with respect to eligibility for prices established by the Act must be made aware of Commission requirements applicable to these determinations, including the manner in which the Commission will review such determinations.

After consideration of the problems associated with any delay in promulgating implementing regulations, the Commission has reached the conclusion that because the regulations must be effective by December 1, 1978 good cause exists to limit as described above notice and public procedure on this proposal. Full notice and public procedure on the proposal at this time, which as a practical matter would result in a delay of the effective date of the regulations beyond the effective date of the NGPA, are impractical and contrary to the public interest. It should be emphasized that all of the procedures described above will provide the fullest possible opportunity for public participation during the entire process leading to the promulgation of final regulations.

IV. Written Comments

Interested persons are invited to submit written comments on the proposed regulations to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N. E., Washington, D. C. 20426. Comments should reference Docket No. RM79-3 on the outside of the envelope and on all documents submitted to the Commission. In view of the short comment period available on these proposed regulations, and in order that the Commission be able to take into account as many comments as possible, the Commission requests that persons submitting comments assist in three ways. First, persons should identify specifically the section or subpart they are addressing. Second, comments should clearly state whether they involve technical, policy or legal matters. Finally, where comments urge a different approach from one presented, specific alternative language should be proposed to the extent practicable.

Fifteen (15) copies should be submitted. To the extent possible, all comments and related information received by the Commission by November 20, 1978, will be considered prior to the promulgation of interim regulations on November 27, 1978. All comments will be retained and considered prior to the promulgation of final regulations.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Energy Administration Act, 15 U.S.C. 761 *et seq.*, Natural Gas Policy Act of 1978, P.L. ———, Department of Energy Organization Act, P.L. 95-91, E.O. 12009, 42 F.R. 46267)

In consideration of the foregoing, it is proposed to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,

Secretary.

Part 2—General Policy and Interpretations

1. Part 2 is amended by deleting § 2.68 in its entirety.

Part 157—Applications for Certificates of Public Convenience and Necessity and for Orders Permitting and Approving Abandonment Under Section 7 of the Natural Gas Act

2. Part 157 is amended by deleting §§ 157.22 and 157.29 in their entirety and by adding new Subparts C (§§ 157.45 through 157.52) and D (§ 157.53), to read as follows:

Subpart C—Exemption of Emergency Sale Arrangements for Natural Gas from Certificate Requirements

Sec.

157.45 Purpose.

157.46 Definitions.

157.47 Exemptions from certificate requirements.

157.48 Terms and conditions of emergency transactions.

157.49 Price ceilings for emergency transactions.

157.50 Treatment of revenues from assigned volumes.

157.51 Reporting requirements for emergency transactions.

157.52 Waiver of requirements for emergency transactions.

§ 157.45 Purpose.

(a) The purpose of this subpart is to prescribe the conditions under which certain emergency transactions involving the construction and operation of facilities or the sale or transportation of natural gas in interstate commerce are exempt from the requirements of section 7 of the Natural Gas Act. Requirements relating to certain arrangements for the

transportation of natural gas, including transportation in emergency situations, are set forth in Part 284 of this chapter. Requirements relating to certain arrangements for the transportation of emergency natural gas by interstate pipelines on behalf of another interstate pipeline are set forth in this subpart.

(b) It shall be the policy of the Commission to monitor emergency natural gas transactions to the extent necessary to assure compliance with the requirements of this subpart.

§ 157.46 Definitions.

For purposes of this subpart:

(a) "Emergency" means:

(1) a situation where the gas supply either available or expected to be available would require the interstate pipeline company or distribution company to impose curtailment on its system;

(2) a sudden unanticipated loss of natural gas supply; or

(3) a situation in which the pipeline purchaser, in good faith, determines that immediate action is required or is reasonably anticipated to be required for protection of life or health or for maintenance of physical property.

(b) "Qualified seller" means any intrastate pipeline, interstate pipeline, or distribution company.

(c) "Qualified purchaser" means a distribution company or interstate pipeline.

(d) "Interstate pipeline" means any natural gas company as defined in section 2(6) of the Natural Gas Act which is engaged in the transportation by pipeline of natural gas.

(e) "Distribution company" means any person (or governmental entity) who receives natural gas for local distribution and resale to natural gas users.

(f) "Intrastate pipeline" means any person (other than an interstate pipeline) engaged in the transportation by pipeline of natural gas.

(g) "Emergency natural gas" means natural gas sold or transported to alleviate an emergency in accordance with this subpart.

§ 157.47 Exemptions from certificate requirements.

(a) Any qualified seller or other person engaged in the sale of emergency natural gas, or in the construction and operation of facilities for the sale of emergency natural gas, is exempt from the requirements of section 7 of the Natural Gas Act, to the extent that (1) the sale of emergency natural gas or the construction or operation of facilities is necessary to alleviate an emergency and (2) the sale, construction or operation is conducted in accordance with the provisions of this subpart.

(b) Any interstate pipeline transporting emergency natural gas on behalf of any other interstate pipeline is exempt from any other requirement of section 7 of the Natural Gas Act if such transportation is in accordance with this subpart.

(c) Participation in any transaction described in paragraph (a) of this section shall not subject any person to the jurisdiction of the Commission under the Natural Gas Act except to the extent provided in this subpart.

§ 157.48 Terms and conditions of emergency transactions.

(a) *General conditions.*

(1) Qualified purchasers may purchase emergency natural gas in accordance with the provisions of this subpart but should make every reasonable attempt to conduct their operations in such a manner as to minimize or, if possible, to avoid continuing reliance upon emergency natural gas supplies.

(2) In applying the definition of emergency, flexibility will be accorded interstate pipelines and distribution companies to account for colder than normal winter weather and to accommodate operations under effective curtailment plans. A reasonable relationship should exist between volumes purchased under this subpart and the volumes which are anticipated to be needed during the emergency.

(3) When a distribution company purchases, or a direct sale customer or distribution company requests assignment of emergency natural gas, a responsible official of the distribution company or direct sale customer shall advise the interstate pipeline which will make the deliveries, before commencement of the deliveries, that the emergency exists or is imminent and shall provide the interstate pipeline with such information as may be required within sufficient time to enable the inter-

state pipeline to make the reports required in § 157.51 of this subpart.

(4) After notice and opportunity for a hearing, the Commission may take appropriate action to insure compliance with this subpart. Upon a determination by the Commission that a person has engaged in emergency transactions and has failed to comply with the conditions of this subpart, the Commission may, in addition to any other remedies, declare the person ineligible to engage in further emergency natural gas transactions without prior Commission approval.

(b) *Duration.*

Emergency transportation under this subpart shall be limited to a period of not more than 60 consecutive calendar days, except in the following cases:

(1) In the event that the Commission determines that there is a natural gas emergency which is national or regional in scope, emergency transactions may continue for such period as the Commission may by order prescribe.

(2) Emergency transactions under this subpart may be continued for an additional period of not more than 60 consecutive days where (i) fifteen days prior to the end of the initial 60-day period, the qualified purchaser files a petition requesting a waiver so as to permit one additional 60-day period of exemptions describing fully the continued emergency, and (ii) the Commission does not, within the 15-day period, by order, prohibit continuation of the emergency transactions for such additional period.

(c) *Cost of facilities.*

No cost associated with facilities installed by interstate pipelines in connection with emergency transactions shall be included in the interstate pipeline's jurisdictional rates unless a certificate of public convenience and necessity has been issued authorizing such facilities.

(d) *System supply and direct assignment of supplies.*

(1) Interstate pipelines may purchase emergency natural gas for general system supply for an emergency.

(2)(i) Interstate pipelines may purchase emergency natural gas and directly assign volumes and costs associated with such gas, including transportation costs, to its direct sale and distribution company customers faced with an emergency, if the customer or company complies with paragraph (a)(3) of this section.

(ii) An interstate pipeline, at its discretion, may choose to establish a separate account to cover the cost of all assigned emergency purchases and allocate costs in that account to the individual assignment customers on a weighted average cost basis. If an interstate pipeline purchases emergency gas supplies for direct assignment in quantities greater than related emergency requirements, then the balance may be used for general system supply. It is expected that such excess emergency natural gas volumes will be small and that pipelines will make every reasonable attempt to balance assignments with supplies. Interstate pipelines may also act as brokers or agents without compensation in acquiring and transporting emergency natural gas for distribution companies faced with an emergency and shall cooperate with these companies in arranging for such acquisition and transportation.

§ 157.49 Price ceilings for emergency transactions.

(a)(1) Rates for transportation by an interstate pipeline under this subpart shall be computed in accordance with subparagraph (2) of this paragraph. Sales by interstate pipelines shall be made at rates prescribed in their tariffs, except that if the natural gas is purchased for assignment to particular direct customers or distribution companies, the natural gas will be priced to recover the cost of purchased gas plus transportation costs as provided in subparagraph (2) of this paragraph.

(2)(i) If an interstate pipeline has on file with the Commission a transportation rate schedule applicable to transportation arrangements under Subpart A of Part 284, the interstate pipeline shall use the rates contained in that schedule.

(ii) if an interstate pipeline does not have on file with the Commission a transportation rate schedule applicable to transportation arrangements under Subpart A of Part 284, the interstate pipeline may elect either:

(A) to base its rates upon the methodology and cost used in designing rates to recover the transmission and related

storage costs included in its then effective sales rate schedules; or

(B) to use the rates contained in a transportation rate schedule on file with the Commission which the interstate pipeline determines covers service comparable to transportation service under Subpart A of Part 284.

(b) The Commission will examine the prudence of emergency purchases by interstate pipelines, except that a rebuttable presumption of prudence shall be accorded to the extent that the rates paid do not exceed the maximum lawful price specified in § 271.202 of this chapter.

§ 157.50 Treatment of revenues from assigned volumes.

An interstate pipeline purchasing emergency natural gas for assignment to particular direct customers or distribution companies shall credit the revenues attributable to the sale of the emergency gas less the cost of the purchased gas plus an allowance of 1.0 cent per Mcf for out-of-pocket costs except where the pipeline can show that:

(a) its currently effective rates are based upon billing determinants which include a representative level of sales associated with assigned volumes; or

(b) its currently effective rates reflect a representative level of revenues associated with sales of assigned volumes which have been credited to the cost of service.

§ 157.51 Reporting requirements for emergency transactions.

(a) Within 48 hours after commencement of deliveries of emergency natural gas, the interstate pipeline shall notify the Commission by telegram of the sale, stating the specific nature and duration of the emergency; the amount of emergency natural gas to be purchased or transported on a daily basis, the name of the seller, transporter, and any person to whom the emergency natural gas is to be assigned; and the price.

(b) For any period during which an interstate pipeline engages in any transaction for emergency natural gas, the interstate pipeline shall file with the Commission, within thirty days after the end of the calendar quarter, whether the transactions are completed or in progress, a sworn statement and four conformed copies thereof, which shall include the following information:

(1) identification of each emergency transaction completed or in progress;

(2) the volumes of emergency natural gas delivered during the quarter under each transaction;

(3) the total revenue or other compensation received by each seller for each emergency transaction during the quarter;

(4) the total amount of revenue or other compensation received for each emergency transaction during the quarter;

(5) the charges and the methods by which the pipeline determined compensation for the transportation of assigned emergency gas;

(6) information relied on to determine eligibility for each transaction;

(7) the volumes of emergency natural gas included in system supply for pipeline emergencies;

(8) a statement from a responsible company official attesting that the activities of the interstate pipeline were carried out in accordance with the requirements of this subpart and to the best of his or her knowledge, an emergency did exist or was reasonably anticipated, and a sworn statement from a responsible company official of each purchasing distribution company or each direct sale customer or distribution company which requested the assignment of emergency supplies describing the emergency circumstances as required by § 157.48(a)(3).

§ 157.52 Waiver of requirements for emergency transactions.

The Commission may by order waive the requirements of this subpart in connection with any emergency transaction to the extent required by the public interest.

Subpart D—Exemption of Natural Gas Service for Drilling, Testing, or Purging from Certificate Requirements

§ 157.53 Drilling of gas or oil wells and testing or purging of new natural gas pipeline facilities.

(a) Construction and operation of facilities necessary to render direct natural gas service for use in the drilling of gas or oil wells or for the use in the testing and purging of new natural gas pipeline facilities are exempted from the certificate requirements of section 7(c) of the Natural

Gas Act, when the construction and operation of such facilities are conducted in accordance with paragraph (b) of this section.

(b) Operations undertaken to render direct natural gas service shall be terminated upon the completion of the well or the purging or testing of the pipeline facilities. Persons undertaking any construction or operation of facilities or service under this section shall file an original and two copies of an annual statement, by February 1 of each year, describing their activities hereunder.

¶ 31,999 Purchased Gas Adjustment Clause

43 F.R. 53770 (November 17, 1978).

[18 CFR Part 154]

RATE SCHEDULES AND TARIFFS

Proposed Rulemaking Which Would Clarify the 36-Month Purchased Gas Adjustment Clause Cost of Service Filing Requirement

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking in Docket No. RM79-2.

SUMMARY: The Commission proposes to amend its rules to clarify existing purchased gas cost adjustment clause regulations for interstate natural gas pipelines. If adopted, the regulations would require a full cost review of a pipeline's rates at least every 3 years if the pipeline has a purchased gas cost adjustment clause in its tariff.

DATE: Comments are due on or before December 11, 1978.

ADDRESS: File comments with: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Charles E. Bullock, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4232.

A. Background

The Commission's regulations covering purchased gas adjustment clause (PGA clause) provisions in pipelines' FERC gas tariffs require a pipeline restate its base tariff rate at least every 36 months. The filing is accompanied by a cost of service study for the most recently available 12 months of actual costs. The intent of these regulations is to insure that pipelines which are granted the right to maintain a PGA clause in their tariffs will be subject to a full rate review at least once every 36 months as provided by the current § 154.38(d)(4)(vi)*(a)*.

The beginning of the 36-month period is determined by § 154.38(d)(4)(vi)*(b)*, which now states:

"(b) If a section 4(e) case is filed before the expiration of the 36-month period, a new 36-month period will start running when the proposed rates go into effect. Rates determined by the Commission in section 4(e) or a 5(a) proceeding or rates in a settlement agreement approved by the Commission shall establish the new base tariff rate when they become effective pursuant to a final order, and a new 36-month period will start running".

In the Federal Power Commission (FPC) order Nos. 452 and 452-A, the FPC allowed pipelines to include purchased gas adjustment provisions in their tariffs to permit them to file abbreviated rate filings to reflect changes in purchased gas costs without filing a general section 4 rate case showing the pipeline's overall costs and revenues. However, to insure that its overall costs and revenues were in balance, the FPC, in those orders, promulgated § 154.38(d)(4)(vi) to require that a pipeline's base tariff rate be restated at least once every 3 years, accompanied by a full cost of service and revenue study.

The present § 154.38(d)(4)(vi)*(b)* allows a pipeline in a section 4(e) rate settlement to update its original cost of service, and to establish a new base tariff rate after the rates in the docket originally become effective, subject to refund, in that docket.[1] This could encourage delays in resolving rate cases by encouraging pipelines to delay negotiating settlements so as to establish new base tariff rates after the date the rates originally become effective subject to refund.

Furthermore, it is not clear from the language of § 154.38(d)(4)(vi)*(a)* that the 36-month overall rate review requirement is a continuing obligation, and not one merely to be met after a PGA clause first becomes effective.

Summary of the Proposed Amendment

This Commission believes that the most appropriate way to accomplish the objective of § 154.38(d)(4)(vi) is to start the 36-month period from the latest of three dates. These are the dates on which (1) the proposed rates in a general section 4(e) rate case, which is filed before the expiration of the last 36-month period, become effective after notice, and suspension if any; or (2) rates are established by final order pursuant to a general section

5(a) rate investigation; or (3) a revised base tariff rate becomes effective, subject to refund, as a result of a filing made pursuant to § 154.38(d)(4)(vi)*(a)*. Accordingly, this Commission proposes to amend § 154.38(d)(4)(vi)*(b)* to reflect the method for determining the 36-month period, as discussed above. Furthermore, the Commission proposes to amend § 154.38(d)(4)(vi)*(a)* to make it clear that the 36-month overall rate review requirement is a continuing obligation, and not merely one to be met after a PGA clause first becomes effective.

PUBLIC COMMENT PROCEDURES

Interested persons may participate in this proposed rulemaking by submitting written data, views, or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before December 11, 1978. Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-2), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

(Administrative Procedure Act (5 U.S.C. 553), Natural Gas Act, as amended (15 U.S.C. 717), Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, it is proposed to amend Part 154, Subchapter E, Title 18, Code of Federal Regulations, as set forth below:

1. Section 154.38 is proposed to be amended in paragraph (d) by revising clauses (vi)*(a)* and (vi)*(b)* of subparagraph (4) to read as follows:

§ 154.38 Composition of rate schedule.

(d) *Statement of rate.* * * *

(4) * * *

(vi) * * *

(a) Upon the expiration of 36 months after the effective date of the PGA clause, and thereafter, upon the expiration of 36 months from the date the base tariff rate was last established pursuant to the provisions of clause (vi)*(b)*, the company shall file a tariff sheet(s) restating its rates to establish a new base tariff rate. The Company shall state its agreement that this filing will automatically be subject to refund concurrently with the filing at the end of 36 months of the tariff sheets establishing a new base tariff rate until an agreement is reached or a Commission determination is made. With this tariff sheet(s) the company shall file a study in the form and with the content prescribed by § 154.63 of the regulations, except statements O and P, to support the new base tariff rate. (If the company has a section 5(a) case pending a final order or has made a section 4(e) filing for which the proposed rates would not become effective before termination of the 36-month period, a study from that proceeding may be utilized.) This study shall be based upon actual costs for the 12 months of most recently available experience, provided that the 12-month period used ends not more than 4 months prior to the expiration of the 36-month period. Annualization for changes which actually occurred in the 12 months will be permitted. This study shall be served on the company's jurisdictional customers and interested State commissions concurrently with the company's filing with the Commission.

(b) For purposes of clause (vi)*(a)* of this subparagraph, the 36-month period shall begin, and the base tariff rate shall be deemed to have been established, on the latest of the dates on which: the rates in a general section 4(e) rate case, which is filed before the expiration of the last 36-month period, has become effective after notice, and suspension if any; or rates are established by final order pursuant to a general section 5(a) rate proceeding, if that occurs prior to the expiration of the last 36-month period; or a revised base tariff rate becomes effective, subject to refund, as a result of a filing made pursuant to clause (vi)*(a)* of this subparagraph.

—Footnote—

[1] See: Algonquin Gas Transmission Co., order issued Oct. 13, 1978, in Docket No. RP78-74.

¶ 32,000 Protection of Essential Agricultural Uses from Curtailment of Gas Deliveries by Interstate Pipelines

43 F.R. 56091 (December 19, 1978).

[10 CFR Part 580]

[Docket No. RM79-5]

PROTECTION OF ESSENTIAL AGRICULTURAL USES FROM CURTAILMENT OF NATURAL GAS DELIVERIES BY INTERSTATE PIPELINES

Public Hearing and Opportunity for Comment

NOVEMBER 29, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Public Hearing and Opportunity for Comment.

SUMMARY: On November 22, 1978, the Federal Energy Regulatory Commission (Commission), in the exercise of its discretion under section 404 of the Department of Energy Organization Act (DOE Act), determined that the proposed rule of the Economic Regulatory Administration (ERA), Department of Energy (DOE) (43 FR 54660, November 22, 1978), relating to the protection of essential agricultural uses from curtailment of natural gas deliveries by interstate pipelines, may significantly affect the Commission's function pursuant to section 402(a)(1)(E) of the DOE Act. Section 402(a)(1)(E) relates to the establishment, review and enforcement of curtailments of natural gas under the Natural Gas Act. The Commission therefore requests the Secretary of Energy (Secretary) to refer the proposed rule to it and is providing notice to the public that it will receive comments and hold a public hearing with respect to the proposal in conjunction with the ERA. The dates provided in this notice of written comments, request to speak, and the hearing date correspond to the dates established by ERA for these procedures.

DATES: Written comments due January 19, 1979; public hearing January 10, 1979; requests to speak due December 27, 1978.

ADDRESS: The hearing will be held at Room 2105, M Street NW., Washington, D.C. 20461.

FOR FURTHER INFORMATION CONTACT: Alexander M. Peters, Office of General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4227.

SUPPLEMENTARY INFORMATION: On November 16, 1978, the ERA issued a proposed rule (43 FR 54660, November 22, 1978) relating to the protection of essential agricultural uses from curtailment of deliveries of natural gas by interstate pipelines. The rule was referred to the Commission on November 16, 1978, for its consideration under section 404 of the DOE Act.

The rule was proposed pursuant to section 401(a) of the Natural Gas Policy Act of 1978 (NGPA), which was enacted on November 9, 1978. Section 401(a) of the NGPA requires the Secretary to prescribe and make effective, not later than 120 days after the date of enactment of the statute, a rule which provides that to the maximum extent practicable, no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for any essential agricultural use unless such curtailment does not reduce the quantity of natural gas delivered for an essential agricultural use; or, is necessary to meet the requirements of high-priority users. Also Section 401(a) of the NGPA provides that if the Commission, in consultation with the Secretary of Agriculture, determines by rule or order that use of an alternate fuel is economically practicable and that the fuel is reasonably available as an alternative to natural gas for use in an essential agricultural use, the provisions of subsection (a) shall not apply with respect to any curtailment of deliveries for such use. The remaining subsections of section 401 require the Secretary of Agriculture to determine essential agricultural use requirements; provide the Secretary of Agriculture the right to intervene in any proceeding before the Commission which is conducted in connection with implementing the requirements of the rule prescribed in subsection (a); and, define the terms "essential agricultural use" and "high-priority user."

The Secretary is directed to promulgate the rule required pursuant to section 401(a) of the NGPA pursuant to his authority under the DOE Act to establish

priorities for curtailments under the Natural Gas Act. *See* section 403(a) of the NGPA. Likewise the Commission is required to implement the rules promulgated by the Secretary pursuant to its authority in section 402(a)(1)(E) of the DOE Act to establish, review, and enforce curtailments under the Natural Gas Act. *See* section 403(b) of the NGPA.

In its review of the proposed rule, the Commission intends to examine the administrative feasibility of implementing the rule in its current form. The Secretary's proposed regulation will also be examined in conjunction with the Commission's current curtailment responsibilities. As the Statement of Managers suggests the examination should be limited:

> . . . the Commission is instructed to reopen curtailment plans that are already in effect under the Natural Gas Act only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment priority schedule [established by the Secretary]. The conferees were concerned that these changes not burden the Commission with lengthy proceedings which might throw existing curtailment plans into disarray. . . . [T]he conferees do not intend the reopening of curtailment plans for this limited purpose to result in adoption of a new base year for curtailment purposes. S. Rep. No. 95-1126, 95th Congress, 2nd Sess. 113 (1978)

Thus, the Commission's interest in the proposed rule results from the need to conform its current responsibilities with rule promulgated by the Secretary. Accordingly, the Commission has requested the Secretary to refer the proposed rules to it. Comments are requested on the effect of the Secretary's proposed rule upon the Commission's curtailment functions pursuant to section 402(a)(1)(E) of the DOE Act.

In accordance with section 404(b), following the public comment period and after consultation with the Secretary, the Commission will either (1) concur in the adoption of the rule as proposed, (2) concur in the adoption of the rule only with changes the Commission recommends, or (3) recommend that the rule not be adopted. The Commission's action will be published in the FEDERAL REGISTER along with an explanation of the reasons for its action. Subsection (c) of section 404 states that the Secretary shall then have the option of (1) issuing the rule (if the Commission has concurred), (2) issuing the rule with any changes recommended by the Commission, or (3) ordering that the rule not be issued.

WRITTEN COMMENTS AND PUBLIC HEARING PROCEDURES

Interested persons may participate in this proceeding by submitting written data, views and arguments by January 19, 1979 to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-5), and give reasons for any recommendations. An original and 14 conformed copies, each containing a summary of contents, should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the comments may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

PUBLIC HEARING PROCEDURES

The Commission and the ERA will hold a joint public hearing in this proceeding at 2000 M Street NW., Washington, D.C. on January 10, 1979, beginning at 9:30 a.m. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may file a request to participate in the hearing with the Secretary of the Commission at 825 North Capitol Street NE., Washington, D.C., prior to 4:30 p.m., December 27, 1978 or with the ERA, in accordance with the procedures announced in its Notice of Proposed Rulemaking, by December 27, 1978.

Requests to participate at the hearing should include a reference to Docket No. RM79-5 as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. The hearing panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. At the conclusion of the initial oral statement, if time permits, persons who have made oral statements will be given the opportunity to make rebuttal statements. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

By direction of the Commission.

LOIS D. CASHELL,
Acting Secretary.

[The next page is 32,021.]

Proposed Regulations

44 Federal Register (1979)

¶ 32,001 Natural Gas Required for Essential Agricultural Uses

44 F. R. 3052 (January 15, 1979)

NATURAL GAS REQUIRED FOR ESSENTIAL AGRICULTURAL USES

Natural Gas Policy Act of 1978; Interstate Pipeline Curtailment Plans

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Natural Gas Policy Act of 1978 (NGPA), in section 401, requires interstate pipeline curtailment plans, to the maximum extent practicable, to protect the requirements of essential agricultural uses. This Notice of Proposed Rulemaking contains a proposed regulation for the implementation of that section from March 9, 1979—October 31, 1979.

DATES: Written comments by January 22, 1979. Public hearings: January 22, 1979—Washington, D.C. at 9:30 a.m.

ADDRESSES: Send comments to Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (Reference Docket No. RM 79-13).

Hearing location: Hearing Room A, 825 North Capitol Street, N.E., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Romulo L. Diaz, Jr., Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-3771, or

Martin A. Burless, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. (202) 275-4349.

SUPPLEMENTARY INFORMATION:

PREAMBLE TO THE INTERIM CURTAILMENT RULE

BACKGROUND

Section 401 of the Natural Gas Policy Act of 1978 (NGPA) seeks to assure that natural gas required for essential agricultural uses will not be curtailed unless curtailment is required to protect the needs of enumerated high-priority users.

Section 401(a) provides that not later than 120 days after the date of enactment the Secretary of Energy shall prescribe and make effective a rule which provides that no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for any of the enumerated high-priority users. This rule must be enacted by March 9, 1979.

Section 401(c) states that the Secretary of Agriculture shall certify to the Secretary of Energy and to the Federal Energy Regulatory Commission the natural gas requirements for essential agricultural uses in order to meet the requirements of full food and fiber production.

Pursuant to section 403(b) of NGPA and section 402(a)(1)(F) of the Department of Energy Organization Act, the Federal Energy Regulatory Commission is charged with implementing the rules prescribed under section 401 under its authority to establish, review, and enforce curtailments, under the Natural Gas Act. The purpose of this rule is to implement, effective March 9, the Secretary of Energy's rule prescribed under section 401(a).

This interim rule will be effective from March 9, 1979, until October 31, 1979. During this interim period inter-

state natural gas pipelines will provide relief from curtailment where necessary to high-priority users and essential agricultural users in accordance with a new tariff provision which this rule directs that the pipeline file. This tariff provision is analogous to the existing life and property tariff provision that pipelines have filed pursuant to § 2.78(a)(4) of the Commission's rules of practice and procedure. This emergency relief mechanism has in the past been used to grant relief from curtailment which would have resulted in danger to life, health, and physical property. The Commission drew on this experience in drafting the present rule so that during this interim period interstate pipelines may provide relief from curtailment to high-priority users and essential agricultural uses under a mechanism with which they are familiar, and which they have successfully utilized in the past.

The proposed rule is an interim rule which will only be effective during a brief portion of the winter heating season. The rule will provide relief, when appropriate, during the summer season. The rule will only come into use if there is a threat of curtailment of essential agricultural users or high-priority users. Under the proposed rule, the maximum volume of gas which can be delivered is the lesser of the volumes the user would receive under the presently effective pipeline curtailment plan or its highest volume used during the last 3 years. Both of these measures of use would be based on the comparable curtailment periods as utilized by the interstate pipeline. Thus, they may be calculated on a daily, monthly, seasonal or annual basis.

In general the Commission believes the Congress intended to utilize as the basis of the section 401 curtailment priorities the base period volumes included in the various pipeline curtailment plans adjusted for alternative fuel capability. The proposed permanent rule is based on this concept. However, the proposed interim rule would implicitly rather than explicitly consider alternate fuel use by reducing the requirements of those users who utilized less than their base period volumes to the high volume used during the last 3 calendar years. The Commission believes that it is reasonable to presume that where a user has been curtailed, alternate fuel has been used in place of natural gas. In those situations where curtailment could not be offset and the facility was temporarily closed, the use of a 3 year period permits a calculation that will only reflect shutdowns that took place in all three 3.

The permanent rule for the implementation of section 401 will set forth a mechanism for ascertaining alternate fuel capability on a more direct and analytical basis. Because of the short lead time imposed by section 401 and considering the short period, the Commission has determined that this more detailed evaluation of requirements and alternate fuel capability is infeasible for purposes of interim implementation. To attempt to acquire the necessary data during this period of time would impose an impossible burden on the end users, distributors, pipelines and the Commission. It is the Commission's judgment that the proposed rule is the most practicable method of implementing section 401 by March 9.

As previously noted, the proposed method of calculating essential agricultural requirements attempts to take account of both natural gas requirements and alternative fuel capabilities in a manner that will be administratively feasible and not unduly burdensome considering the short lead time and the short period in which the rule will be effective. Generally, the volumes of gas attributable to end users under a pipeline curtailment plan are the maximum volumes that would be taken regardless of alternate fuel capability. If base period requirements alone were utilized, with no consideration to alternative fuel capabilities, there would be a danger, in a situation requiring relief under this provision, of energy requirements that can utilize alternate fuels utilizing natural gas even though the alternative fuel would be economically practicable and reasonably available in accordance with the section 401(b) policy. Such a large shift in energy requirements would place demands on the interstate system that could be difficult to meet out of system supply. It would also cause large unexpected disruptions in

fuel usage patterns. The periods of time involved are so short that effective planning and adjustments would be difficult. Also, as noted, the permanent rule provides for evaluation of alternative fuel capabilities and the public interest would not be served by short-term shifts on to gas and then off again when the permanent rule is implemented.

The Commission's rule treats high-priority users and essential agricultural users differently with respect to the applicability of the alternative fuel requirement. The statute only applies an alternative fuel test to essential agricultural uses and not to high-priority users. However, the Commission notes that the Department of Energy's proposed rule implementing section 401 would apply the alternative fuel criterion to high-priority users as well. The Commission decided not to follow this practice for the interim rule. In the absence of the data review the data verification committee will provide for the post November 1, 1979 period, the Commission is concerned that treating the two categories in the same fashion might lead to situations endangering life, health or the maintenance of physical property. Such a threat would be contrary to the spirit of this section of NGPA. Additionally, implementation of this procedure under the interim rule might contravene section 605 of the Public Utility Regulatory Policies Act of 1978, the "Savers Keepers Provision."

The Commission is contemplating changes to reflect the changes in its direct purchase program caused by the Natural Gas Policy Act of 1978 and the Public Utilities Regulatory Policies Act of 1978. The rule under consideration would provide a direct purchase program for agricultural users with alternate fuel capability, and for new and expanded uses. The proposal under consideration, if adopted, would insure access to natural gas for all agricultural requirements, both those included in pipeline curtailment plans and those not covered thereby. This rule under consideration would, if adopted, be an important complement to the present proposed rule.

The interim rule requires that all volumes delivered under this provision be used to serve the requirements, calculated in accord with the provision of this rule, of high-priority users and essential agricultural uses. To the extent that this procedure may require a local distribution company to obtain authorization from its state regulatory authority, it is expected to do so prior to requesting a waiver or adjustment of curtailment under this rule. Natural gas delivered under the provisions of this rule are intended to go to those categories of users identified in the statute.

The rule proposes a formula to determine the portion of a local distribution company's high-priority and essential agricultural requirement that the interstate pipeline must satisfy. The rule's purpose is to restate the policy that interstate pipelines are only required to satisfy a fixed share, based on historical contribution to a local distribution company's total supplies, of any local distribution company's additional requirements to serve high-priority users and essential agricultural uses. The formula is as follows:

$$V = (HPR_t - HPS_t)\ \frac{(IPS)}{(LDCS)}$$

V = volume of additional supplies that may be requested of each interstate pipeline supplier

HPR_t = high-priority requirements for current period

HPS_t = high-priority supply for current period

IPS = interstate pipeline supply to local distribution companies in corresponding curtailment period upon which the interstate pipeline's curtailment plan is based

LDCS = total LDC supply in corresponding curtailment period upon which the interstate pipeline's curtailment plan is based.

This provision will insure that additional demand for supplies is not placed on interstate systems that has not been present in the past. Volumes required under this provision will come from the general system supply of the interstate pipeline and thus, the grant of relief under this provision may result in some increase in the level of curtailment on the interstate pipeline's system including increased curtailment of lower priority requirement to the distributor requesting relief under this provision.

Where the increased system curtailments would result in one distributor having to curtail high-priority users or other essential agricultural uses, that

distributor will be curtailed to a lesser degree. That distributor's curtailment will be limited to the volumes that can be curtailed without affecting high-priority users or essential agricultural uses.

The Commission has benefited from the consultation with the Department of Agriculture called for under section 401(b). The Commission understands that this consultation process does not necessarily imply that the Department of Agriculture concurs in this rule.

SUMMARY OF THE REGULATION

The regulation implements section 401 of the NGPA on an interim basis for the period March 9-October 31, 1979. This regulation applies to all sales of natural gas by interstate pipelines during this period. It authorizes the granting of relief to high-priority users as defined in the statute and essential agricultural uses as they are certified by the Secretary of Agriculture pursuant to rule.

The rule defines the terms schools and hospitals so that similar institutions are included within those definitions. This obviates the requirement to independently define the term similar institutions.

In determining the requirements of the end-users that can be met under this rule the high-priority user's requirements are limited to those requirements currently included in the interstate natural gas pipeline's effective curtailment plan. Thus, if an interstate pipeline curtails using a past fixed base period, the high-priority user will be entitled to receive those volumes it would be entitled to receive based on that base period. Where an interstate natural gas pipeline curtails on some other basis, that basis will be used to determine the high-priority user's natural gas requirements which may be met under this provision.

As noted earlier, however, the Commission plans to broaden its direct sales program to make it more accessible to meet demands not covered by natural gas pipeline curtailment plans. This program will complement this proposed rule.

In determining actual agricultural use, users will be permitted to receive the lesser of the amount they would be entitled to receive under the interstate pipeline's currently effective curtailment plan or their highest volumes of natural gas purchased during the appropriate curtailment period of 1976, 1977, or 1978. This provision is designed to grant essential agricultural users the maximum volumes possible during this interim period. By going back three years the Commission anticipates that the requirements of essential agricultural uses adjusted for alternative fuel capabilities will be adequately represented during one of those three years. The Commission has determined that this is the most practicable way that essential agricultural requirements can be determined considering the time period. For the permanent rule a more precise mechanism will be proposed. The Commission has considered permitting essential agricultural users to project their requirements over a future period of time but has concluded that cannot be implemented in a practicable manner at least for the interim period.

The only limitations on relief contained in this interim rule are that the end-user be included in the interstate pipeline's currently effective curtailment plan. This excluded agricultural users who may have attached to a local distribution company after the close of a pipeline's base period and who are not considered in the pipeline's curtailment plan. However, as previously noted the contemplated revisions in the direct purchase program may make natural gas available to these end-users.

The proposed tariff provision provided that if upon the request of any direct sale customer or local distribution company the interstate pipeline determines that such customer qualifies for the waiver or adjustment of the level of curtailment in order to meet the needs of high-priority users or essential agricultural uses, the interstate pipeline shall waive or adjust curtailment to permit the volumes required to meet the high-priority user's needs or the essential agricultural user's needs to be supplied. Local distribution companies and direct sale customers are required to notify the interstate pipeline when the projected level of curtailments is such that curtailment of high-priority users or essential agricultural users will result.

Where the interstate pipeline can grant requested relief the interstate natural gas pipeline is authorized to do so without prior approval or prior filings with this Commission.

The regulation requires that the interstate pipeline notify the Commission within 48 hours of the commencement of deliveries. The Commission will cause such notice of the waiver or adjustment of curtailment to be published in the FEDERAL REGISTER and will permit complaints to be filed within 45 days of such notice. The purpose of limiting the complaint period to 45 days is to foreclose an unlimited period of potential liability.

Where a request for relief is rejected by an interstate pipeline or the interstate pipeline cannot grant sufficient relief to the end user without resulting in curtailment of other high-priority users or essential agricultural uses the extraordinary relief provision of the Commission's Rules of Practice and Procedure are open to the essential agricultural use or high-priority user.

WRITTEN COMMENT AND PUBLIC HEARING PROCEDURE

Interested persons are invited to submit written comments on this proposal to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426. Comments concerning Subpart A of Phase I must be submitted by January 22, 1979, so that a final rule may be promulgated to be effective February 6, 1979.

Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-13), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed.

The Commission intends to hold a public hearing on this proposal. This hearing shall be held on Monday, January 22, 1979, but comments at that time shall be limited to Subpart A of Phase I. The dates and locations of public hearings concerning other parts of the proposal will be announced as soon as practicable.

The public hearing on Subpart A of Phase I will be held on January 22, 1979, at 9:30 a.m., in Hearing Room A, 825 North Capitol Street, NE., Washington, D.C. 20426. Persons interested in participating should contact Kenneth F. Plumb, Secretary, at the Federal Energy Regulatory Commission, (202) 275-4166, by January 18, 1979.

In consideration of the foregoing it is proposed to add a new Part 281, Subpart A, Title 18, Code of Federal Regulations, as set out below.

By direction of the Commission.

KENNETH F. PLUMB,
Secretary.

PART 281—NATURAL GAS CURTAILMENT

Subpart A—Interim Curtailment Rule

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AUTHORITY: Administrative Procedure Act, 5 U.S.C. 553, Natural Gas Act, as amended, (15 U.S.C. 717), Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 Fed. Reg. 46267, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791), Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Federal Energy Administration Act, (15 U.S.C. 761), Public Utility Regulatory Polices Act of 1978, Pub. L. 95-617.

Subpart A—Interim Curtailment Rule

§ 281.101 Purpose.

The purpose of this subpart is to implement, on an interim basis, section 401 of the NGPA in order to provide that for the period March 9, 1979, through October 31, 1979, the curtailment plans of interstate pipelines protect, to the maximum extent practicable, deliveries of natural gas for essential agricultural uses and for high-priority uses.

§ 281.102 Applicability.

This subpart applies to sales of natural gas by an interstate pipeline during

the period March 9, 1979, through October 31, 1979, if the pipeline is curtailing its sales of natural gas to high-priority or essential agricultural users.

§ 281.13 Definitions.

(a) *NGPA definitions.* Terms defined in the NGPA shall have the same meaning for purposes of this subpart as they have under the NGPA, unless further defined in this subpart.

(b) *Subpart A definitions.* For purposes of this subpart:

(1) "NGPA" means the Natural Gas Policy Act of 1978.

(2) "School" means a facility, the primary function of which is delivering instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and noneducational activities are not included under this definition unless the latter activities are merely incidental to the delivery of instruction.

(3) "Hospital" means a facility, the primary function of which is delivering medical care to patients who remain at the facility. Outpatient clinics or doctors' offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(4) "Essential agricultural use" means any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" under section 401(c) of the NGPA.

(5) "Essential agricultural user" means a person who uses natural gas for an essential agricultural use and who is entitled to receive natural gas, directly or indirectly, from the interstate pipeline under its currently effective curtailment plan.

(6) "High-priority use" means any use of natural gas:

(i) in a residence;

(ii) in a commercial establishment in amounts of less than 50 Mcf on a peak day;

(iii) in a school or hospital; or

(iv) by any person who is designated by the Secretary of Energy as a "high-priority user" under 10 CFR 580.2 (c)(iv).

(7) "High-priority requirements" for a curtailment period from a particular interstate pipeline means the maximum volume the high-priority user or local distribution company on behalf of the high-priority user would be entitled to purchase for high-priority use under the interstate pipeline's currently effective curtailment plan but not including volumes a high-priority user may receive solely by operation of this subpart or volumes obtained under § 2.79.

(8) "High-priority user" means a person who uses natural gas for high-priority uses.

(9) "Essential agricultural requirements" for a curtailment period from a particular interstate pipeline means the lesser of:

(i) The highest metered volume of natural gas purchased from an interstate pipeline either under a direct sale contract or under a contract between the local distribution company and the interstate pipeline in the corresponding period of calendar year 1976, 1977, or 1978 and consumed for an essential agricultural use but excluding any volumes received solely through operation of this subpart or volumes obtained under § 2.79; or

(ii) the maximum volume the essential agricultural user or local distribution company on behalf of the essential agricultural user would be entitled to purchase for essential agricultural use under the interstate pipeline's currently effective curtailment plan but excluding any volumes received solely through operation of this subpart or volumes obtained under § 2.79.

(10) "Curtailment period" means the curtailment period, e.g., daily, monthly, seasonal, or annual used by the interstate pipeline in its curtailment plan.

§ 281.104 Interim rule.

Each interstate pipeline shall file tariff sheets which provide for waiver in accordance with § 281.105 of the otherwise applicable provisions of its curtailment plan, if necessary, to supply essential agricultural uses or high-priority uses. The tariff sheets shall be filed not later than February 6, 1979, with a proposed effective date of March 9, 1979, and shall meet the terms and conditions in this subpart.

§ 281.105 Waiver.

(a)(1) Subject to paragraph (a)(2) of this section, interstate pipelines shall

waive or adjust the effective level of curtailment for its local distribution company customers and direct sale customers which have submitted to the interstate pipeline high-priority requirements or essential agricultural requirements in the manner prescribed and determined in accordance with paragraph (b) of this section.

(2) If an interstate pipeline's own records contain information which directly conflicts with the statements made under oath under paragraph (b) of this section, the pipeline shall not waive or adjust its currently effective level of curtailment for such local distribution company customer or direct sale customer.

(b) The local distribution company customer or direct sale customer shall demonstrate qualification for waiver by submitting, under oath, the following information to their interstate pipeline suppliers:

(1) The volume of natural gas, calculated in accordance with the provisions of this rule, that each of its high-priority users and essential agricultural users estimates will be necessary for its high-priority requirements and essential agricultural requirements during the curtailment period, except that the local distribution company may aggregate the high-priority requirements for residential and small commercial customers who use less than 50 Mcf on a peak day.

(2) A statement from the local distribution company and each high-priority user, except residential and small commercial customers who use less than 50 Mcf on a peak day, and essential agricultural user that the volumes specified in paragraph (b)(1) of this section will be used solely for high-priority uses or essential agricultural uses.

(3) The volume of natural gas for which waiver is requested is calculated as the sum of the volumes in paragraph (b)(1) of this section less the estimated supplies available to serve essential agricultural use and high-priority use, absent waiver.

(4) If a local distribution company customer or a direct sale customer has more than one source of natural gas supply it shall prorate the volume for which waiver may be requested from its interstate pipeline supplier by multiplying the volume calculated under paragraph (b)(3) of this section by the ratio that each interstate pipeline supplied for the corresponding period on which the interstate pipeline's currently effective curtailment plan is based to the total supply of the local distribution company or direct sale customer in the corresponding curtailment period. The calculation and the volume so prorated to each interstate pipeline supplier shall be submitted to the particular interstate pipeline supplier from whom waiver is requested.

§ 281.106 Volumes for which waiver may be granted.

(a) Subject to the conditions in paragraph (b), when a customer qualifies for waiver, the interstate pipeline supplier shall deliver, from its system supply, the additional volumes specified in § 281.105(b).

(b)(1) If a local distribution company customer or direct sale customer notifies the interstate pipeline that because of the level of curtailment resulting from the granting of a waiver for deliveries to other essential agricultural users, the local distribution company will curtail a high-priority user or another essential agricultural user, or a direct sale customer will be unable to meet its high-priority requirements or essential agricultural requirements, such local distribution company customer or direct sale customer shall be exempt from the adjusted level of curtailment to the extent necessary to meet high-priority requirements or essential agricultural requirements.

(2) If a local distribution company customer or direct sale customer notifies the interstate pipeline that, because of the level of curtailment resulting from waiver for deliveries to other high-priority users, the local distribution company will curtail other high-priority users, or a direct sale customer will be unable to meet its high-priority requirements, such local distribution company customer or direct sale customer shall be exempt from the adjusted level of curtailment to the extent necessary to meet such high-priority requirements.

§ 281.107 Filing requirements.

Each interstate pipeline which makes deliveries of natural gas under § 281.106 shall file a statement with

the Commission indicating the direct sale customer or local distribution company customer and its high-priority users and essential agricultural users and the volumes on a customer and end-user basis to which deliveries are made under § 281.106. The filing shall be made within 48 hours of the commencement of deliveries and shall include a copy of the information submitted by the local distribution company or direct sale customer under § 281.105(b).

§ 291.108 Notice, complaint, remedy.

(a) *Notice.* The Commission shall publish in the FEDERAL REGISTER notice of all waivers made under this subpart.

(b) *Complaint.* Any person aggrieved by any action taken pursuant to the provisions of this rule may file, within 45 days of notice, a complaint pursuant to § 1.6 of this chapter.

(c) *Remedy.* If the Commission determines that a willful and knowing violation of these regulations took place it shall take whatever action it deems appropriate in the circumstances. Such action may include, among others, payback in kind or in dollars by the person benefiting from the waiver.

§ 281.109 Extraordinary relief.

If an interstate pipeline rejects a request for waiver under § 281.105 or if the deliveries made pursuant to a waiver under § 281.106 are inadequate to forestall an emergency situation, the local distribution company customer or direct sale customer may file a request for relief from curtailment under § 1.7. The request shall contain the information required in § 2.78(b).

¶ 32,002 Natural Gas Curtailment

44 F. R. 3725 (January 18, 1979)

[Docket No. RM79-15]

NATURAL GAS CURTAILMENT

Notice of Proposed Rulemaking Implementing Section 401 of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Natural Gas Policy Act of 1978 (NGPA), in section 401, requires interstate pipeline curtailment plans, to the maximum extent practicable, to protect the requirements of essential agricultural uses. This Notice of Proposed Rulemaking contains a proposed regulation of the implementation of that section.

DATES: Written comments by February 26, 1979.

PUBLIC HEARINGS: Dates and locations to be announced. The Commission solicits suggestions as to where it would be appropriate to hold other proceedings in addition to the one to be held in Washington, D.C. Such requests should be submitted by January 25, 1979 to the address below.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM79-15).

FOR FURTHER INFORMATION CONTACT:

Romulo L. Diaz, Jr., Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-3771.

or

Martin A. Burless, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-4349.

PREAMBLE TO THE PERMANENT CURTAILMENT RULE

BACKGROUND

Section 401 of the Natural Gas Policy Act of 1978 (NGPA) seeks to assure that natural gas required for essential agricultural uses will not be curtailed unless curtailment is required to protect the needs of enumerated high priority users.

Section 401(a) provides that not later than 120 days after the date of enactment of the NGPA the Secretary of Energy shall prescribe and make effective a rule which provides that no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for any essential agricultural use except to meet the requirements of enumerated high priority users.

Section 401(c) states that the Secretary of Agriculture shall certify to the Secretary of Energy and to the Federal Energy Regulatory Commission and natural gas requirements for essential agricultural uses in order to meet the requirements of full food and fiber production.

Pursuant to section 403(b) of the NGPA and section 402(a)(1)(E) of the Department of Energy Organization Act, the Federal Energy Regulatory Commission is charged with implementing the rules prescribed under section 401 under its authority to establish, review, and enforce curtailments under the Natural Gas Act. By a separate rulemaking the Commission has proposed rules to give effect to section 401 for the period March 9 1979, 120 days after the date of enactment, through October 31, 1979. The rules proposed herein are to be effective November 1, 1979, the beginning of the first full winter heating season when section 401 will be in effect. However, as will be discussed, public comment is solicited on when this rule should be made effective.

Title IV of the NGPA creates new priority classifications for high prior-

ity users as defined in the statute, essential agricultural uses, and essential industrial process and feedstock uses. There is no statutory deadline for implementation of a rule regarding essential industrial process and feedstock uses. The Economic Regulatory Administration of the Department of Energy is studying curtailment priorities and it is likely that a rule regarding essential industrial process and feedstock uses will be proposed by the Secretary of Energy upon its completion.

By this rulemaking the Commission proposes a method for the permanent implementation of section 401. In developing this proposed rule the Commission has had the benefit of consultation with the United States Department of Agriculture as contemplated by section 401. The Commission is aware, however, that consultation does not imply concurrence by the USDA with all aspects of these proposed regulations.

Under the proposed rule pipeline curtailment plans will be amended so that high priority end users that are not now in the highest priority of pipeline curtailment plans will be reclassified into Priority One. Pipeline curtailment plans will create a new Priority Two which will contain the requirements necessary to serve essential agriculture uses. All other pipeline curtailment categories will remain the same and their order will remain the same but they will be below these two new categories.

The proposed changes in curtailment plans are to be implemented on November 1, 1979. It will be necessary for the interstate pipelines to revise their end use profiles and curtailment plans to reflect the changes brought about by the enactment of NGPA. Thus, although the rule will not be implemented until November 1, substantial work will be required before that date to prepare for its implementation. The Commission anticipates as soon as this rule is promulgated end users, local distribution companies, and interstate pipelines will immediately commence working towards its implementation.

The Commission requests interested parties to comment on the proposed date for implementation of these changes in curtailments. It is possible that the rules promulgated under section 402 may require similar modifications to the ones proposed here. There may be benefits to postponing permanent implementation until after those rules are promulgated. However, it is unlikely that the section 402 rule will be in place for the 1979-80 heating season so that if section 401 were implemented with section 402, some interim plan would have to be adopted for the 1979-80 heating season. Comments and suggestions are requested on this issue.

The Commission recognizes that there may be interstate pipelines with existing curtailment plans that will not require modification. For example, there may be interstate pipelines that do not have any essential agricultural uses on their systems and whose existing curtailment plans already classify high priority users ahead of all other uses. Another situation might find a pipeline's natural gas supply and existing curtailment plan adequate to forestall curtailment of high priority users and essential agricultural uses for the foreseeable future. In such cases it is not the Commission's intent to compel alteration of the existing curtailment plan needlessly. If an interstate pipeline's existing curtailment plan, given current supply projections, adequately protects those uses the statute seeks to protect, the interstate pipeline may file for an exception to the provisions of this rule.

Where modification of a pipeline's curtailment plan is required, individual pipelines may require a plan which varies from that in the proposed rule. Once again, the Commission seeks to be sensitive to the differences among interstate pipelines. Should differing treatment be appropriate for individual pipelines the Commission is prepared to recognize this fact and respond accordingly.

In past curtailment proceedings the parties have often arrived at a settlement of all issues without resort to adjudicatory proceedings before the Commission. This procedure may be appropriate here, and nothing in the proposed rule precludes any interstate pipeline and its customers from proposing, as a settlement, a curtailment plan that differs from that set out in our proposed rules. Such a settlement

will be evaluated by the Commission in light of its ability to meet the statutory goal of protecting, to the maximum extent practicable, high priority users and essential agricultural uses.

SUMMARY OF PROPOSED RULE

The proposed rule would have interstate pipelines file revised curtailment plans setting forth two new categories, placing high priority users and essential agricultural uses ahead of existing curtailment categories. The Commission views this as a reclassification of existing curtailment plans so that uses once categorized on another basis would now be categorized as high priority users or essential agricultural uses.

The requirements of high priority users would be the same as the requirements for those users currently reflected in existing interstate pipeline curtailment plans.[1] Thus, were an interstate pipeline curtails on a past fixed base period the high priority user requirements would be those reflected in the base period data. Where an interstate pipeline uses an alternate approach to curtailment then the high priority user's requirements would be computed on the same basis as they are computed in the interstate pipeline's presently effective curtailment plan.

Under the Commission's proposed rules essential agricultural uses requirements will be calculated on the same basis as they are calculated in the interstate pipeline's presently effective curtailment plan. Thus, where an interstate pipeline curtails based on a past fixed base period, the requirements will be the base period allocation. Where another basis is used that method will be used. After this volume is calculated, the user's alternate fuel capability will be subtracted out. The Commission is of the view that this will help insure that uses without alternate fuel capability, those most in need of protection, receive the highest curtailment classification. Failure to examine alternate fuel capability would result in the rule protecting those with alternate fuel capability on the same basis as those without that capability, thereby diminishing the quality of the protection afforded to those who most need it.

Where a determination is made that certain requirements can be satisfied with alternate fuel, those requirements will not be reclassified. This may result in certain end user's volumes being split among various curtailment categories. This is not unusual and has been done in the past with industrial needs which may be divided among process, feedstock and boiler fuel requirements with curtailment of the lower priority uses occurring while the same end user's high priority needs are served.

This proposed rule is linked to the basis upon which the interstate pipeline now curtails. This is designed to result in minimal disruption of existing curtailment plans as expressed in the NGPA Conference Report at page 113:

> For purposes of implementing this section, the Commission is instructed to reopen curtailment plans that are already in effect under the Natural Gas Act only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment priority schedule. The conferees were concerned that these changes not burden the Commission with lengthy proceedings which might throw existing curtailment plans into disarray. Therefore, the conference agreement includes the term "to the maximum extent practicable" to assure that the Commission has the necessary flexibility in implementing any changes. For example, the conferees do not intend the reopening of curtailment plans for this limited purpose to result in adoption of a new base year for curtailment purposes.

In the course of the Commission's consultation with the Department of Agriculture, pursuant to section 401(b) of the NGPA, two alternative methods of calculating agricultural requirements were suggested.[2] The Commission is giving serious consideration to these proposals as alternatives that might be adopted in place of the procedure in the proposed rule. The Secretary of Agriculture has stated:

[1] The Commission's rule conforms to the Department of Energy's proposed rule insofar as it considers the alternate fuel capability of high priority users. If the Department of Energy's proposed rule is altered, appropriate modifications will be made to this rule.

[2] Memoranda submitted to the Commission by the USDA pursuant to this consultation are in the public record in this docket.

The Department of Agriculture has taken the position that the proposed rule would not achieve the statutory intent that access of agricultural users to pipeline supplies of gas be protected at significantly higher levels than previously and that such additional protection of gas supply must be available to agricultural users on equally favorable economic terms with other pipeline gas supplies that are protected against curtailment.

The USDA has recommended the following as one possible way to achieve the statute's intent in a practicable way:

1. Small-scale agricultural uses, as defined in the January 3, 1979, draft FERC rule, would be placed in the high-priority classification under a broad interpretation of the definition of "commercial establishments using less than 50 mcf per peak day." Such users would be presumed to lack the economic practicability to utilize a fuel other than natural gas in their operations, and would be protected in their access to gas on demand within appropriate tariff provisions or up to contract entitlements.

2. For essential agricultural uses under 401(f)(1)(A), protect all projected and verified natural gas requirements of certified essential agricultural users up to contract entitlements, with a rebuttable presumption that such users lack the economic practicabiltity to utilize a fuel other than natural gas in their operations.

3. For essential agricultural uses under 401(f)(1)(B), natural gas requirements would be computed as:

(a) the certified peak use, in the time frame normally employed by the pipeline, during a rolling 3-year base period; plus

(b) the volume of natural gas the essential agricultural user would have consumed in that curtailment period but for curtailment or plant shutdowns.

For determination of past curtailments and plant shutdowns, the burden of coming forward with the relevant verifiable information would be upon the agricultural users, and such information would be rebuttably presumed to be accurate. This would generally eliminate sequential determination on economic practicability and reasonable availability of alternate fuels; agricultural users would be rebuttably presumed to lack the economic practicability to utilize a fuel other than natural gas up to the base corrected for past curtailments and plant shutdowns.[3]

Comment is invited on the USDA preferred proposal, regarding (1) its sufficiency in fulfilling the intent of the statute and (2) its practicability of implementation.

However, should the Commission decide to adopt a historical base period approach the Department of Agriculture would advance an alternative proposal, although USDA emphasizes that the proposal set out above is the preferred approach in its view. USDA's alternative proposal follows:

1. Small-scale agricultural uses, as defined in the January 3, 1979, draft rule, would be placed in the high-priority classification under a broad interpretation of the definition of "commercial establishments using less than 50 mcf per peak day." Such users would be presumed to lack the economic practicability to utilize a fuel other than natural gas in their operations, and would be protected in their access to gas on demand within appropriate tariff provisions or up to contract entitlements.

2. For all other essential agricultural uses, natural gas requirements would be computed as:

(a) the certified peak use, in the time frame normally employed by the pipeline, during a rolling 3-year period; plus

(b) the volume of natural gas the essential agricultural user would have consumed in that curtailment period but for curtailment or plant shutdowns.

3. For determination of past curtailments and plant shutdowns, the burden of coming forward with the relevant verifiable information would be upon the agricultural user, and such information would be rebuttably presumed to be accurate. This would generally eliminate sequential determination on economic practicability and reasonable availability of alternate fuels; agricultural users would be rebuttably presumed to lack the economic practicability to utilize a fuel other than natural gas up to the base corrected for past curtailments and plant shutdowns.[4]

Comment is invited on the USDA's second proposal regarding (1) its sufficiency in fulfilling the intent of the statute and (2) its practicability of implementation.

Should USDA's second approach be adopted, the Commission would continue to employ the data verification committees of the various interstate pipelines in order to examine requirements. The data verification committees would be instructed to determine that small users be deemed to have no alternate fuel capability and that they be given treatment comparable to high priority uses. For all other essential

[3]Memorandum from Secretary Bergland to Commissoner Hall, Subject: USDA Comments on FERC Proposed Rule, dated January 9, 1979. The definition of small agricultural use proposed by USDA is the same as that in the proposed rule.

[4]Memorandum from Mr. Barton to Commissioner Hall, January 6, 1979.

agricultural uses the data verification committee would be instructed to determine the peak use of the essential agricultural use over the past three years, with such use determined on the basis on which the interstate pipeline's curtailment plan is based such as daily, seasonally, monthly, or annually. If the essential agricultural user demonstrated that it had been curtailed during this period of time and that the use of a three year rolling period did not adequately cover a period where there had been no curtailment, the volumes that would have been used if there were no curtailment would be added into this requirement. Implementing this rule, the Commission would eliminate its presumption of past alternate fuel use as in indication of economic practicability and reasonable availability of alternate fuels now. Any challenges to essential agricultural users requirements calculated under this method would be adjudicated with the burden of proof on the challenger, and any adjustment in the essential agricultural users requirements would be prospective only.

How essential agricultural use requirements are to be calculated including the determination of alternate fuel capability is a major issue. The Commission specifically requests comments on this aspect of the proposed rule in general and both of the USDA's proposals in particular. Parties who prefer other alternate approaches are requested to submit the proposed methods for computing the requirements of essential agricultural uses. The practical implications of the various proposals on interstate natural gas pipeline systems and the impact on natural gas demands by consuming category should be analyzed and evaluated.

Parties to this proceedings should be aware that the Commission is considering adoption of a direct purchase program as contemplated by section 608 of the Public Utility Regulatory Policies Act of 1978. The proposed changes would provide an opportunity for agricultural users of natural gas whose requirements are not covered by pipeline curtailment plans to obtain natural gas by means of direct purchases. The changes in this program, if adopted, should provide an important complement to the rule proposed here.

To reclassify high priority users or essential agricultural uses, it will be necessary for the pipelines to identify such end users. The Commission recognizes that many of those classified as high priority uses in the NGPA are already classified in pipeline curtailment Category One. To the extent such consumers are known and their requirements, whether individually or aggregated by distributor, are known to the interstate natural gas pipeline they would not be expected to file requests for reclassification nor would their requirements be subject to reexamination by data verification committees. The requests for reclassification should contain the information set out in the proposed rule and any other information that a person seeking reclassification deems relevant. This requested information is comprehensive so as to obviate the need for additional requests for information.

The rule provides that suppliers of natural gas, where appropriate, are to review the request for reclassification and indicate whether to the best of their knowledge, information, and belief the statements made by the end user are true. These requests for reclassification will then be forwarded to the interstate pipeline suppliers.

Each interstate pipeline will use its Data Verification Committee to review the data submitted. Interstate pipelines that do not presently have data verification committees are to form them. Interstate pipelines with existing data verification committees should continue to employ those committees.

The Commission anticipates that the data verification proceedings will be informal forums for the amicable resolution of disputes. The Commission has set out in its proposed rule the minimum requirements for membership but individual pipelines may choose to add additional members, and groups of customers may designate an individual to serve as their representative. While the proposed regulation specifies those groups who we expect to be represented, attendance by any member of the Data Verificaiton Committee is, of course, not mandatory.

The Data Verification Committee is expected to examine the information submitted by the end user and determine whether the end user actually

qualifies for reclassification as a high priority user or essential agricultural use. Once this decision is made the Data Verification Committee is expected to examine the requirements of the high priority user and the essential agricultural use and compute them in accordance with the provisions of this rule. Where necessary, high priority users, agricultural users or challengers may appear before the Data Verification Committee.

The report of the Data Verification Committee, as spelled out in this rule, is required to be in detail. It is to be the basis of the interstate pipeline's tariff filing. Once the interstate pipeline files the proposed tariff sheets with the Data Verification Committee's report the Commission will review the tariff filing and Data Verification Committee report. Where there are challenges to the Data Verification Committee report, or the Data Verification Committee has not been able to reach an agreement on a recommendation, challenges will be heard by the Commission. In those proceedings the burden of proof will be on those who seek to change the status quo. Thus, if an essential agricultural use is challenged based on alleged availability of alternate fuel and its economic practicability and that end user has not used alternate fuel in the past, the burden of proof would be on the challenger.

Where a consumer has been denied reclassification by the data Verification Committee or where a consumer with a high priority or essential agricultural use believes its requirements were inaccurately stated by the Data Verification Committee the challenge to the Data Verification Committee report will be construed as a complaint under Section 1.6 of the Commission's regulations.

The proposed rule also defines alternative fuel capability for the purposes of implementation of section 401. The definition of alternate fuel capability contained in section 401(b) of the NGPA differs from that presently contained in the Commission's regulations. The new definition of alternate fuel capability is proposed solely for the purposes of this rule so as not to require a relitigation of existing curtailment plans. One difference from the Commission's existing rule is that propane and other gaseous fuels are not excluded from the definition of alternate fuel by this rule. The Commission believes that the standard set out in the statute, reasonably available and economically practicable will provide an adequate basis for dealing with propane and other gaseous fuels on a case-by-case basis, or where appropriate, on a blanket basis. Comments are requested on the Commission's proposed treatment of propane and other gaseous fuels.

It may not be possible for the Data Verification Committee to examine the alternative fuel capability criteria in each case becasue of time constraints. In such situations the Data Verification Committee may elect to submit its report calculating alternate fuel capability based ona ctual past use under the presumption established in the rule. It would be desirble for the Data Verification Committee to consider all factors in reaching its decision but it is also important to complete determination of requirements under the permanent rule as promptly as possible in order to limit uncertainty.

The proposed rule deems small essential agricultural users, those consumers using less than 50 Mcf per day, at each separately metered delivery point as not having alternate fuel capability. Additionally, small low load factor agricultural users are presumed not to have alternate fuel capability.[5] These features of the rules are designed to minimize litigation involving small users and low load factor users so that the Commission's implementation program does not become backlogged because of excessive adjudication of disputes involving small volumes of natural gas. The presumption also reflects experience with small users that indicates that they generally do not have economically feasible alternatives. Generally, small natural

[5]Load factors are computed by taking the total annual consumption and dividing that figure by 365. The resulting figure, the average daily consumption, is then divided by the consumption on the day of highest use during the year. If the result is equal to or less than .20 the consumer is a low load factor user within this definition.

gas users do not have alternate fuel capability and would have great difficulty converting to alternative fuel such as coal, solar energy, or waste heat. As a general proposition in most curtailment cases the Commission has classified small volume users with a relatively high priority.

Where there are challenges to the report of the Data Verification Committee and the associated tariff filing the Commission will establish procedures to adjudicate those challenges. It is hoped that the use of the data verification committees will minimize the number of disputes that require adjudication. Where the Commission determines that a high priority user or an essential agricultural use has been misclassified by the Data Verification Committee the Commission will grant relief prospectively. However, where a consumer received excess volumes while the Commission was adjudicating the challenge to its requirements or status, the Commission reserves the right to order payback of excess volumes in appropriate cases.

PUBLIC COMMENT PROCEDURES

Interested persons may participate in this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before February 26, 1979. Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-15), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

The Commission intends to allow an opportunity for the oral presentation of data, views and arguments. One such proceeding will be held in Washington, D.C. and additional proceedings will be scheduled at appropriate times and places. The Commission solicits suggestions as to where it would be appropriate to hold such other proceedings and the names of those interested in appearing. Such requests should be submitted by January 25, 1979 to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Requests should reference Docket No. RM79-15 and indicate whether the request is for Washington, D.C. or elsewhere. The dates and exact locations of the public hearings will be announced as soon as practicable.

(Administrative Procedure Act (5 USC § 553), Natural Gas Act, as amended (15 U.S.C. 717), Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267), Federal Energy Administration Act (15 U.S.C. 761), Energy Supply and Environmental Coordination Act (15 U.S.C. 791), Natural Gas Policy Act of 1978, Pub. L. 95-621, Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617.)

In consideration of the foregoing, it is proposed to add Part 281, Subpart B, Title 18, Code of Federal Regulations, as set forth below:

By direction of the Commission.

KENNETH F. PLUMB,
Secretary.

PART 281—NATURAL GAS CURTAILMENT

Subpart B—Proposed Rule for Curtailment of Natural Gas Under Section 401 of NGPA

Sec.

281.201 Purpose.
281.202 Applicability.
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281.204 General rule.
281.205 Request for classification.
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281.207 Data Verification Committee.
281.208 Protests and challenges.

AUTHORITY: (Administrative Procedure Act (5 USC § 553), Natural Gas Act, as amended (15 U.S.C. 717), Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267), Federal Energy Administration Act (15 U.S.C. 761), Energy Supply and Environmental Coordination Act (15 U.S.C. 791), Natural Gas Policy Act of 1978, Pub. L. 95-621, Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617.)

§ 281.201 Purpose.

The purpose of this subpart is to implement section 401 of the NGPA in order to provide that effective November 1, 1979, the curtailment plans of interstate pipelines protect to the maximum extent practicable, deliveries of natural gas for essential agricultural uses and for high-priority uses.

§ 281.202 Applicability.

This subpart applies to sales of natural gas made by an interstate pipeline on and after November 1, 1979, if the pipeline is curtailing its sales of natural gas.

§ 281.203 Definitions.

(a) *NGPA definitions.* Terms defined in the NGPA shall have the same meaning for purposes of this subpart as they have under the NGPA, unless further defined in this subpart.

(b) *Subpart B definitions.* For purposes of this subpart:

(1) "NGPA" means the Natural Gas Policy Act of 1978.

(2) "School" means a facility the primary function of which is delivering instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and noneducational activities are not included under this definition unless the latter activities are merely incidental to the delivery of instruction.

(3) "Hospital" means a facility the primary function of which is delivering medical care to patients who remain at the facility. Outpatient clinics or doctors' offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(4) "Essential agricultural use" means any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR § 2900.3 as an "essential agricultural use" under section 401(c) of the NGPA.

(5) "Essential agricultural user" means a person who uses natural gas for an essential agricultural use.

(6) "High-priority use" means any use of natural gas:

(i) In a residence;

(ii) In a commercial establishment in amounts of less than 50 Mcf on a peak day;

(iii) In a school or hospital; or

(iv) By any person who is designated by the Secretary of Energy as a "high-priority user" under 10 CFR § 580.2(c)(2)(iv).

(7) "High-priority user" means a person who consumes natural gas for a high-priority and who does not have installed alternate fuel capability.

(8) "High-priority requirements" for a curtailment period from a particular interstate pipeline means the high-priority requirements as determined by the Data Verification Committee under § 281.207 or the high-priority requirements as determined by the Commission, as appropriate.

(9) "Essential agricultural requirements" for a curtailment period from a particular interstate pipeline means the essential agricultural requirements as determined by the Data Verification Committee under § 281.207 or the essential agricultural requirements as determined by the Commission, as appropriate.

§ 281.204 General rule.

(a) Each interstate pipeline shall file tariff sheets amending its effective curtailment plan to provide that the total requirements for high-priority uses and essential agricultural uses are fully met prior to delivering natural gas for any other end use. These end uses are designated end-use priorities one and two and, for all interstate pipelines with existing curtailment plans based on numbered priority of use categories, those existing categories are renumbered to follow sequentially the new priorities one and two. In the event the interstate pipeline has insufficient gas available to meet both its high-priority requirements and essential agricultural requirements, the high-priority requirements will be fully served before any deliveries are made for essential agricultural requirements.

(b) The tariff sheets shall be filed on October 1, 1979, with a proposed effective date of November 1, 1979. The tariff sheets shall contain the conditions prescribed in paragraph (a) and indicate the volumes as determined by the Data Verification Committee under § 281.207, needed to serve the requirements of the high-priority users and the essential agricultural users for which there is no alternate fuel. The

report of the Data Verification Committee shall be the basis of the tariff filing and shall be filed with the tariff sheets required by this subpart.

§ 281.205 Request for classification.

(a) Any end user of natural gas may file a request with its direct supplier to classify a specified volume of its purchases as high-priority use or essential agricultural use.

(b) Except as provided in paragraph (c), the end user shall submit under oath the following information, where applicable, to its direct supplier:

(1) Name of end user;

(2) Address of end user;

(3) Standard Industrial Classification (SIC) code of activity for which natural gas is required;

(4) Direct supplier of natural gas;

(5) Current curtailment priority classification;

(6) Contract entitlement for the calendar years 1976, 1977, and 1978, computed on the basis or bases utilized by the supplier (e.g., daily, monthly, seasonal, annual);

(7) Actual agricultural use computed on the basis or bases utilized by the supplier (e.g., daily, monthly, seasonal, annual) for the calendar years 1976, 1977, and 1978;

(8) The current requirements of the high-priority end user as reflected in the interstate pipeline's curtailment plan;

(9) If natural gas volumes have been curtailed, the dates of such curtailment and the amount of gas curtailed;

(10) Whether the end user has alternative fuel available;

(11) Whether any fuel other than natural gas, has ever been used by the end user for end uses designated as essential agricultural uses or high-priority use and, if another fuel has been used, the dates of such use and the amount of alternate fuel used; and

(12) Whether fuels other than natural gas are planned to be used in the future; if so, the fuel and the amount involved.

(c) Residential and small commercial customers who use less than the 50 Mcf of natural gas on a peak day are not required to file with their direct supplier. Direct suppliers shall base these requirements on those already included in pipeline curtailment plan or, if none, they may estimate the high-priority requirements of these customers.

(d) The request described in paragraph (b) must be filed with the direct supplier by June 10, 1979.

§ 281.206 Review of requests for reclassification.

(a) *Suppliers.* (1) The natural gas supplier shall determine whether to the best of its knowledge, information and belief, the statements made by the end user requesting reclassification of natural gas as a high-priority use, or as an essential agricultural use are true.

(2) Where appropriate, the supplier shall file under oath the information with its interstate pipeline supplier no later than June 25, 1979. a copy of the information shall be sent simultaneously to the appropriate state or local regulatory authority. If the supplier has more than one interstate pipeline supplier, the volumes for which the reclassification is sought shall be prorated among the interstate pipeline suppliers on the same basis as proration was made for purposes of the interstate pipeline's effective curtailment plan.

(b) *Interstate pipelines.* No later than June 30, 1979, the interstate pipeline shall forward all requests for reclassification as high-priority use or essential agricultural use to the Data Verification Committee and circulate a list of customers seeking such classification to all its distributors, appropriate State and local regulatory authorities, all parties to its curtailment proceeding and the Commission staff.

§ 281.207 Data Verification Committee.

(a) The Data Verification Committees of each interstate pipeline shall include at a minimum a representative of the interstate pipeline, Commission staff, large and small distributors and appropriate State or local regulatory bodies. If an interstate pipeline does not have a Data Verification Committee, it shall form one.

(b) The interstate pipeline shall convene a meeting of the Data Verification Committee within 10 days of receipt of the information sent to it under § 281.206.

(c) The Data Verification Committee shall review the requests for reclassification and shall make an initial determination of the essential agricultural requirements and high-priority requirements of each person requesting reclassification. The initial determination of the Data Verification Committee shall be made in accordance with subparagraphs (1) and (2).

(1) *High-priority users and essential agricultural users.* The high-priority requirements of a high-priority user and the essential agricultural requirements of an essential agricultural user shall be the maximum volume the high-priority user or essential agricultural user would be entitled to purchase for high-priority use or essential agricultural use under the interstate pipeline's effective curtailment plan, but not including volumes a high-priority user or essential agricultural user may receive solely by operation of Subpart A, or volumes obtained under § 2.79, less volumes of natural gas for which the high-priority user or essential agricultural user has alternate fuel capability.

(2) *Determination of alternate fuel capability.* (i) For purposes of this paragraph and except as provided in clause (ii), alternate fuel capability will be deemed to be equal to the least amount of alternate fuel actually used in the comparable curtailment period of lowest alternate fuel use during the past three years.

(ii) (A) A person whose natural gas consumption for high-priority use or essential agricultural use during the curtailment period on which the interstate pipelines curtailment plan is based did not exceed a peak day requirement of 50 Mcf at each separately metered delivery point is deemed to have no alternate fuel capability.

(B) A person whose natural gas consumption for high-priority use or essential agricultural uses during the curtailment period on which the interstate pipelines curtailments is based did not exceed 300 Mcf on a peak day at each separately metered delivery point and whose average daily requirements for essential agricultural uses, measured over the calendar years 1976, 1977, and 1978 did not exceed 20 percent of such person's peak day requirement for essential agricultural uses measured on the 36-month period ending October 31, 1978, is deemed to have no alternate fuel capability.

(C) The Data Verification Committee shall compile a list reflecting its initial determination of high-priority requirements and essential agricultural requirements. This list shall be prepared by August 1, 1979, and simultaneously a copy shall be mailed to the interstate pipeline, all of its distributors, appropriate State and local regulatory authorities, all parties to its curtailment proceeding and the Commission staff.

(D) Any person aggrieved by an initial determination of the Data Verification Committee may challenge the determination on the basis of the actual use of the natural gas, the volumes of natural gas required for the high-priority use or the essential agricultural use or the alternate fuel capability determination. Any person challenging an initial determination shall be permitted to make an oral or written presentation to the Data Verification Committee.

(E) Subject to the provisions of subparagraphs (1) and (2) the Data Verification Committee may adjust the challenged initial determinations.

(*f*) *Alternate fuel capability.*

(*i*) Any person challenging an initial determination on the basis of alternate fuel capability shall have the burden of proving there is no alternate fuel capability.

(*ii*) For purposes of this subparagraph "alternate fuel capability" means a condition where a fuel other than natural gas could be utilized to achieve the end use of natural gas. The facilities for such use may have actually been installed, but a potential capability to use a fuel other than natural gas also qualifies as an alternate fuel capability. Alternate fuel capability exist when use of alternate fuel is economically practicable and reasonably available to the end user. A fuel other than natural gas is deemed economically practicable when the cost of such other fuel plus the cost of the facilities required to utilize such fuel are, when compared with natural gas on the basis of units of energy displaced, sufficiently similar so that the user might reasonably be expected to use either fuel without serious adverse financial consequences.

(iii) In determining alternate fuel capability as defined in clause (ii), the following factors shall be considered:

(A) Does the facility or industry in question have the installed capacity to use an alternate fuel?

(B) Does the present state of technology permit the use of an alternate fuel to perform the particular end use?

(C) Do other similar types of consumers presently utilize fuels other than natural gas?

(D) If alternate fuel capability is technically feasible, what is the cost of conversion or replacement of facilities so that alternate fuel can be utilized?

(E) What is the projected cost of the alternate fuel?

(F) What is the projected cost of natural gas?

(G) Are there any other out-of-pocket costs required to utilize natural gas?

(H) What part of the end user's total costs is attributable to the cost of fuel?

(I) What competitive disadvantage will the end user suffer if it utilizes a fuel other than natural gas?

(J) What is the projected availability of natural gas for that end user?

(K) What is the projected availability of fuels other than natural gas?

(2) *Essential agricultural requirements.* An end user may request an increase of the initial determination of its essential agricultural requirements on the grounds that the initial determination is not sufficient to satisfy its natural gas needs for full food and fiber production. The Data Verification Committee may increase the essential agricultural requirement up to the contract entitlement if it determines that no other source of natural gas is available to satisfy these requirements including but not limited to purchases by the distributor or end user.

(F) By September 15, 1979, the Data Committee shall make a final determination of the high-priority requirements and essential agricultural requirements of each person seeking reclassification. This determination and the report described in paragraph (g) shall be sent by September 15, 1979 to the interstate pipeline, the pipeline's distributors, appropriate state and local regulatory authorities, all parties to the interstate pipeline's curtailment proceeding, the Commission staff and all customers who sought reclassification.

(G) No later than September 15, 1979, the Data Verification Committee shall prepare a report which contains the following information:

(1) a list by end user indicating:

(i) the volume for which reclassification is sought;

(ii) the standard industrial classification of the end user;

(iii) the alternate fuel capability as determined by the Data Verification Committee; and

(iv) the high-priority requirements or essential agricultural requirements as determined by the Data Verification Committee;

(2) a list by end user and the volumes requested for reclassification for whom a challenge to such reclassification was made if such challenge has not been resolved and the basis, therefore, and a list of those for whom insufficient information existed to make a determination as to whether the essential reclassification is appropriate;

(3) the recommendation of the Data Verification Committee as to the appropriate resolution of any challenge to a request for reclassification as a high-priority user or as an essential agricultural use;

(4) a copy of the minutes of the Data Verification Committee meeting.

§ 281.208 Protests and challenges.

(a) *Protests.* Protests to this tariff filing shall be limited to further challenges to natural gas end users seeking reclassification in either priority-of-service category one or two, challenges by customers who were denied certification by the Data Verification Committee as either high-priority users or essential agricultural users on whose requirements were decreased by the Data Verification Committee. All such protests shall be treated as complaints pursuant to § 1.6 of this chapter. The Secretary of Agriculture may intervene as a matter of right under § 1.8(a)(1) of the chapter in any proceeding initiated under this section.

(b) *Burden of proof.* (1) In the case of a consumer being challenged as to the propriety of its inclusion in prior-

ity-of-service category one or two, the consumer shall have the initial burden of going forward to explain why it should be included in either priority-of-service category one or two. The ultimate burden of proof is upon those challenging the end users inclusion to show conclusively that the end user is not a high-priority user or essential agricultural use, that the requirements of the end users approved by the Data Vertification Committee are not correct or, that alternate fuel technology exists and that use of an alternate fuel is economically practicable and that such fuel is reasonably available.

(2) In the case of challenge by an end user that has been denied certification by the Data Verification Committee as either a high-priority user or essential agricultural use or in the case of a certified consumer whose priority-of-service category one or two requirements were decreased by the Data Verification Committee, the challenge will be construed as a complaint pursuant to § 1.6 of this chapter.

(3) In the case of an end user that has provided insufficient information upon which to conclude that it qualifies for either priority-of-service category one or two treatment, the consumer's request for classification will be construed as a complaint pursuant to § 1.6 of this chapter.

(c) *Commission decision.* (1) If the Commission determines that an end user who has been temporarily classified in priority-of-service category one or two does not qualify for the classification, the end user shall be placed in the appropriate curtailment category.

(2) The Commission, in its discretion, may direct the payback to excess volumes taken while the end user was temporarily misclassified.

(3) If the Commission finds that an end user who was denied certification as a high-priority user or an essential agricultural use qualifies for such status, the end user shall be reclassified on a prospective basis.

(4) If the Commission finds that a certified end user whose requirements were decreased by the Data Verification Committee, warrants the recognition of increased requirements, the increase shall be granted on a prospective bases.

¶ 32,003 Criteria for Powerplant's Design Capacity

44 F. R. 4500 (January 22, 1979)

[Docket No. RM79-10]

POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978

Proposed Criteria for Powerplant's Design Capacity

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Proposed Rule.

SUMMARY: The Powerplant and Industrial Fuel Use Act of 1978 requires the Commission to promulgate rules under which a powerplant's design capacity may be determined. Determination of a powerplant's capacity is necessary because it is an element of various statutory definitions in the Act. By this notice, the Commission has established certain criteria for the design rating and requests comments on how well the proposed rules support the criteria established by the Commission.

DATES: Comments due on or before January 30, 1979.

ADDRESS: Comments referencing Docket No. RM79-10 should be sent to: Kenneth F. Plum, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plum, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, 202-275-4166.

SUPPLEMENTARY INFORMATION: Section 103(a)(18)(D) of the Powerplant and Industrial Fuel Use Act of 1978 (Act) Pub. L. 95-1749, requires the Federal Energy Regulatory Commission (Commission) to promulgate rules under which a powerplant's design capacity may be determined. The determination of a powerplant's design capacity is necessary because it is an element of each of the statutory definitions of the terms "peakload powerplant", "intermediate load powerplant", and "base load powerplant" as provided in section 103(a)(18) of the Act. The definitions of those terms will be used to determine the applicability of certain temporary and permanent exemptions from sections 201 and 202 of the Act, which proscribe the use of natural gas or petroleum as a primary energy source in new electric powerplants, under sections 212(g) and 212(h). The definitions are also to be used to determine the applicability of certain temporary and permanent exemptions from sections 301 and 302 of the Act, relating to existing electric powerplants, under sections 311(f), 312(f), and 312(g) of the Act. Finally, determinations regarding design capacity are necessary under section 501 of the Act, Electric Utility System Compliance Option, in order to determine if existing electric utilities are in compliance with Title III of the Act.

Discussion

The Commission proposes that the rules contained herein be used to determine a powerplant's design capacity. There are a number of powerplant capacity ratings used by the electric power industry. However, these are used principally for operational purposes, reflecting seasonal weather conditions, degradation of a powerplant, or other factors, and may be substantially different from a powerplant's design capacity. The Commission has established criteria that the design rating should be (1) determinable unequivocably from the manufacturer's data and ordinarily not change during a powerplant's physical life, unless there is substantial modification of the unit; (2) a familiar and recognizable quantity throughout the electric power industry; and (3) a published value readily available to any party interested in obtaining it. These criteria and the proposed rules evolving therefrom were developed in consultation with the Staff of the Secretary of

Energy. The proposed rules are summarized below:

(1) The design capacity of a steam-electric generating unit shall be its maximum generator nameplate rating which has been reported to the Energy Information Administration on EIA Form —— (formerly FPC Form 12).

(2) The design capacity of a combustion turbine shall be its peak load rating as defined by both the American National Standards Institute (ANSI) and by the International Standards Organization (ISO). This peak load rating, which applies to units operating for peaking service with a maximum of 2,000 hours per year operation, is based on an ambient temperature of 59 degrees Fahrenheit (15 degrees Celcius) and a pressure of 14.696 psia (sea level). This should be the capacity rating reported to the Energy Information Administration on EIA Form —— (formerly FPC Form 12). If those reported ratings are based on different conditions, they will be adjusted to ISO standard conditions for the purposes of the Powerplant and Industrial Fuel Use Act.

(3) The design capacity of a combined cycle unit shall be the sum of its combustion turbine peak load rating, based on ANSI/ISO standard conditions, and the maximum generator nameplate rating of the steam turbine portion of the unit.

(4) The design capacity of an internal combustion engine shall be the capacity rating which has been reported to the Energy Information Administration on EIA Form —— (formerly FPC Form 12).

The Commission solicits comments from interested parties concerning how well the proposed rules support the criteria established by the Commission. Also, the Commission is interested in any problems or concerns regarding the applicability of the proposed rules in meeting the requirements of the Act.

PUBLIC COMMENT PROCEDURES

Interested persons may participate in this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before January 30, 1979. Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-10), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission.

Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

(Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 F.R. 46267, Powerplant and Industrial Fuel Use Act of 1978, Pub. L. 95-1749)

In consideration of the foregoing, the Commission proposes to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

LOIS D. CASHELL,
Acting Secretary.

Chapter I of Title 18 is amended by adding a new Subchapter J, Part 285 Consisting of § 285.101 to read as follows:

SUBCHAPTER J—REGULATIONS UNDER THE POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978

PART 285—RULES GENERALLY APPLICABLE TO POWERPLANT AND INDUSTRIAL FUEL USE

§ 285.101 Determination of powerplant design capacity.

For purposes of this subchapter, a powerplant's design capacity shall be determined as follows:

(a) *Steam-electric generating unit.* The design capacity of a steam-electric generating unit shall be taken as the maximum generator nameplate rating which has been reported to the Energy Information Administration on EIA Form —— (formerly FPC Form 12).

(b) *Combustion turbine.* The design capacity of a combustion turbine shall be taken as its peak load rating as defined by both the American National Standards Institute (ANSI) and by the International Standards Organization (ISO). This peak load rating, which applies to units operating for peaking service with a maximum of 2,000 hours per year operation, is based on an ambient temperature of 59 degrees Fahrenheit (15 degrees Celcius) and a pressure of 14.696 psia (sea level). If capacity ratings as reported to Energy Information Administration on EIA Form —— (formerly FPC Form 12) are based on different conditions, these reported ratings will be adjusted to ISO standard conditions.

(c) *Combined cycle unit.* The design capacity of a combined cycle unit shall be taken as the sum of its combustion turbine peak load rating, based on ANSI/ISO standard conditions, and the maximum generator nameplate rating of the steam turbine portion of the unit.

(d) *Internal combustion engine.* The design capacity of an internal combustion engine shall be taken as the capacity rating which has been reported to the Energy Information Administration on EIA Form —— (formerly FPC Form 12).

¶ 32,004 Certification of Pipelines Transportation Agreements for Certain High-Priority Uses

44 F. R. 7740 (February 7, 1979).

[Docket No. RM79-18]

CERTIFICATION OF PIPELINE TRANSPORTATION AGREEMENTS FOR CERTAIN HIGH-PRIORITY USES

Proposed Procedures

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Proposed rule.

SUMMARY: The Federal Energy Regulatory Commission gives notice of a proposal to implement Section 608 of the Public Utilities Regulatory Policies Act of 1978. The rule establishes procedures for the certification of transportation of natural gas purchased by agricultural or other high-priority users directly from producers.

DATES: Written comments by March 12, 1979.

ADDRESSES: All filings should reference Docket No. RM79-18 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Robert C. Platt or Philip Yates, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20425, (202) 275-0161.

I. Introduction

On November 9, 1978, the Natural Gas Policy Act of 1978 (NGPA), Pub. L. 96-621, and the Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. 96-617, were enacted. Section 401 of the NGPA upgrades the curtailment priorities of schools, hospitals and essential agriculture users. Section 608 of PURPA adds Section 7(c)(2) to the Natural Gas Act to provide for the transportation of natural gas sold by a producer to an eligible user or produced and consumed by an eligible user (hereinafter referred to as "direct sale gas"). This proposed rule implements, in part, the direct sale authority of PURPA section 608, in conformance with the curtailment policies expressed in section 401 of the NGPA.

This rule reflects four important features of the new regulatory system created by the National Energy Act. First, the former interstate and intrastate markets have been merged. The unification of the natural gas supply market reduces the former problem of attracting gas supplies to the markets served with interstate pipeline system-supply gas. The intent of the new legislation is to preserve access by pipelines to their long-standing sources of supply.

Second, section 608 of PURPA provides an additional basis for the Commission to certificate transportation of direct sale gas. The proposed rule would satisfy the rulemaking envisioned by section 608 with respect to only certain categories of customers, i.e., agricultural and designated high-priority users. However, as will be discussed later, the Commission sees this program as a possible model for other actions implementing section 608 and requests comments and suggestions regarding expansion of this program.

Third, the NGPA substitutes a system of ceiling prices (maximum lawful prices) for the former cost-based, just and reasonable pricing system under the Natural Gas Act. Consequently, the Commission need not review the price of the direct sale gas when it evaluates transportation certificate applications under the proposed rule.

Fourth, Title IV of the NGPA reorders curtailment priorities. Although not specifically mandated by the statute, the Commission believes that the Congressional expression of public policy in section 401 of the NGPA concerning essential agricultural uses and other high-priority uses should be reflected in the Commission's direct sale programs as well.

This proposed rule is one of three rules proposed to carry out the Commission's implementation responsibil-

ities with respect to section 401 of the NGPA. The other two rules (the interim and permanent rules) would implement the NGPA with respect to those natural gas uses now provided for within existing pipeline curtailment plans.[1] This proposed rule would complement these rules and complete the FERC implementation program by providing access to natural gas supplies for those agricultural and high-priority uses without access to pipeline-supply gas.

The proposed direct sale program for agriculture and other high-priority uses, taken with the other two rules, seeks to harmonize some potentially inconsistent aspects of section 401 of the NGPA. On the one hand, section 401 expresses Congress' concern with ensuring adequate supplies of natural gas "* * * to meet the requirements of full food and fiber production." On the other hand, the statute and accompanying Joint Statement of Managers convey a clear Congressional intent to minimize the extent to which present curtailment plans will need to be reformulated to implement this section.

"* * * For purposes of implementing this section, the Commission is instructed to reopen curtailment plans that are already in effect under the Natural Gas Act only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment priority schedule. The conferees were concerned that these changes not burden the Commission with lengthy proceedings which might throw existing curtailment plans into disarray. Therefore, the conference agreement includes the term 'to the maximum extent practicable' to assure that the Commission has the necessary flexibility in implementing any changes. For example, the conferees do not intend the reopening of curtailment plans for this limited purpose to result in adoption of a new base for curtailment purposes." [2]

Commentators in some of the rulemakings pursuant to section 401 of the NGPA have contended that the term "full food and fiber" requires the modification of existing curtailment plans to accommodate both new loads of existing customers as well as new customers. Other commentators have asserted that interpreting section 401 to include load growth would almost certainly require that the base period data of every affected plan be revised, in direct contravention of the instructions by Congress to avoid disruptive changes to the base periods of curtailment plans.

In addition, were load growth for agriculture to be permitted, it seems logical to also permit load growth for the other uses designated by section 401 as higher in priority than essential agricultural uses. Thus, permitting access to interstate pipeline system-supply gas by all new and expanded uses of high-priority consumers designated in section 401 could require precisely the kind of reopening of all existing pipeline curtailment plans that Congress sought to avoid.

Including the proposed direct sales program for agriculture and other high-priority uses as one component in section 401 implementation program is one means of meeting the joint Congressional objectives of assuring that all agricultural uses are given access to natural gas while avoiding the need to roll base periods or otherwise cause major disruptions. Unlike deliveries from pipeline system supply, which are subject to curtailment plans and which are generally based upon historic use, volumes delivered under a direct sale contract are not subject to curtailment and need not be measured against historic use. Hence, a direct sales program does not force the reopening of existing curtailment plans. In addition, because the pipelines' service obligations to existing customers are not placed in issue, new growth of eligible direct sale users can be accommodated without resolving competing claims of existing and future customers. Eligibility for participation in the proposed direct sale program is reserved for certain high-priority customers. The program therefore fits the Commission's overall curtailment policy.

It has been correctly pointed out in other section 401 rulemakings that a direct sales program may give access to natural gas but it does not give

[1] Docket No. RM79-13, Interim Regulations For th Implementation of Section 401, January 10, 1979; RM79-15, Regulation For the Implementation of Section 401, January 12, 1979.

[2] H. Report No. 95-1752, 95th Cong. 2d Sess. 113 (1978). See also H. Report No. 95-1750, 95th Cong. 2d Sess. 113 (1978).

access to pipeline system-supply gas at a rolled-in price. The latter type of access is, of course, more economically beneficial than purchasing gas at current market prices. The NGPA is clear on the need to provide adequate access to natural gas for agriculture.[3] As now envisioned, section 401 would be implemented so that those uses covered by pipeline curtailment plans would have assured access to pipeline system supplies at rolled-in prices and the other high-priority uses would obtain access at current market prices.

The proposed rule implements only a part of the Commission's new authority under section 608 of PURPA and is fashioned solely upon the specific statutory groundwork of section 401. The Commission is cognizant of its responsibility to implement fully section 608 of PURPA. The program proposed by this rulemaking might be expanded to include other categories of consumers. Alternatively, other direct sale programs along the lines of the program proposed here might be developed and tailored for the particular needs of other "high-priority uses". Therefore, the Commission invites comment about possible expansion of the application of its direct sales authority and the terms and eligibility requirements appropriate to any suggested expansion.

The Commission's program for the transportation of direct sales of natural gas between producers and industrial customs established by FPC Order No. 533 and FERC Order No. 2 will not be affected by this proposed rule. Nor does it affect the transportation of natural gas for intrastate pipelines and local distribution companies under NGPA section 311(a).

II. Summary of Proposed Regulation

The proposed Subpart E of Part 157 supplements the Commission's existing direct sale authorization by allowing the transportation of direct sale gas to certain users that may not currently be eligible to have natural gas transported under § 2.79 of this chapter.

Proposed § 157.101 indicates the manner in which such direct sale authority is implemented. As presently proposed, Subpart E would permit the transportation of direct sale gas to all essential agricultural users as certified by the Secretary of Agriculture, and all schools, hospitals and similar institutions.

A transportation certificate under section 7(c)(2) of the Natural Gas Act would be issued to the transporting interstate pipeline. However, as indicated in proposed § 157.101(a), either the pipeline or the eligible user on behalf of the pipeline may make application for the certificate. Because the application must include executed contracts, applications cannot be filed until the producer, pipeline and eligible user all consent to the transaction. Since the proposed regulation imposes filing requirements to be satisfied by either the eligible user or the interstate pipeline providing the transportation service, the Commission welcomes comments on the means by which the filing requirements can be shifted from the pipeline to the eligible user to be served.

Applications for a permanent certificate may include application for a temporary transportation certificate. All applications will be processed on an expedited basis. Although section 7(c)(2) of the Natural Gas Act makes no explicit provision for temporary certificates, section 16 of the Natural Gas Act is sufficient legal authority for the Commission to grant such temporary certificates. (See *Hunt Oil Company* v. *F.P.C.*, 334 F.2d 474 (5 Cir. 1964)).

Temporary certificates may be issued by the Director of the Office of Pipeline and Producer Regulation. This delegation is achieved by including a conforming amendment to § 3.5(f)(1)(iv) of this chapter in this rulemaking. Permanent certificates will be issued by the Commission after notice, an opportunity for protest and, where appropriate, a hearing.

Proposed § 157.102 defines "eligible uses" to include any use certified as an "essential agricultural use" by the Secretary of Agriculture pursuant to section 401(c) of the NGPA, and uses by hospitals and schools or similar institutions as those terms are defined in

[3] There is an important difference of opinion about whether Congress authorized load growth or the general use of gas for boiler fuel purposes.

proposed §§ 281.203(b)(2) and (3) of this chapter. These definitions reflect section 401 of the NGPA. An "eligible user" is defined as anyone who consumes natural gas for an eligible use. Residential and small commercial users have historically been protected from curtailment of service from general pipeline supplies, and NGPA section 311(a) provides these users further protection through local distribution companies. As a result, they do not require the access to direct sales provided under the proposed rule. Additionally, the large number of such users in this category could not be accommodated practically under the direct sale program.

The Commission has determined that its policy governing the transportation of direct sale gas should be expanded to include eligible users who are not facing curtailment, to serve new eligible users, and to supply the increased loads of existing eligible users.

A determination under NGPA section 401(b) by the Commission that an essential agricultural user has an available alternate fuel will have no effect upon that user's eligibility to have its direct sale gas transported. Thus, eligible users can utilize direct sale gas to replace other fuels, in whole or in part, to meet its energy requirements.

Congress, in section 401(f), elevated the previously low-priority boiler fuel use by schools and hospitals to high-priority status. Such a change reflects a shift from "end-use" to "end-product" tests in determining curtailment priorities for the uses designated in NGPA section 401. The Department of Agriculture has used an "end-product" test as the sole criterion for defining "essential agricultural uses" in its proposed rule. The Commission has applied this same test in its proposed definition of "eligible uses" for direct sale gas transportation. The Commission invites comment on the extent to which the "end-product" test derived from NGPA section 401 should be supplemented with an "end-use" test in its definition of "eligible uses".

Proposed § 157.102(c) is an exercise of the Commission's rulemaking authority under section 7(c)(2) of the Natural Gas Act. It determines that "high-priority uses" shall include eligible uses as defined in § 157.102.

Proposed § 157.103 sets out the data that must be supplied in an application for direct sale transportation authorization. Proposed § 157.103(l) requires the reporting of any fees paid to a broker for arranging direct sales. Similar reporting requirements are currently being challenged before the Commission; any conclusion reached in that challenge will be reflected in the final version of § 157.103

Proposed § 157.104 limits the type of gas that qualifies for direct sale transportation by reliance upon the "committed or dedicated" test defined in NGPA section 2(18). This test is designed to prevent the disruption of the offshore supply patterns and to preserve low-cost supplies for interstate system supply. Proposed § 157.104(a) applies the "committed or dedicated" test as of November 8, 1978. This date is used for applying the test because it is used in pricing determinations under NGPA sections 104, 105, 106 and 109 and in deciding which natural gas is subject to the right of first refusal under NGPA section 315(b). Many producers should have previously applied this test in qualifying for the NGPA interim collection procedures as set forth in § 273.201(c)(2) and § 273.202(d)(1)(v) of this chapter.

The selection of the "committed or dedicated" test is predicated upon an additional policy consideration. NGPA section 315(b)(3) gives interstate pipelines the opportunity to match the terms of a sales agreement "substantially accepted in principle" by a competing buyer. Because "committed or dedicated" gas is ineligible for transportation in the proposed direct sale program, and because section 315(b)(3) applies *only* to gas which is "committed or dedicated", the test prevents the proposed direct sales program from affecting the contract terms available to interstate pipelines under section 315(b)(3).

An eligible user seeking to determine whether particular gas reserves qualify for the proposed direct sale program must consider the contractual and abandonment obligations attached to the natural gas in addition to the test proposed in § 157.104 test.

The Commission has considered other eligibility tests, such as basing eligibility on certain NGPA price categories or making all gas supplies eligible. The Commission invites comment on these and other eligibility tests.

Should an applicant wish to transport direct sale gas not eligible for transportation under proposed § 157.104(a), proposed paragraph (b) authorizes a request for a waiver of the § 157.104(a) requirement. For example, the Commission could consider waivers for "committed or dedicated" gas classified under NGPA section 107, even though such natural gas does not qualify under proposed § 157.104(a).

Proposed § 157,105 establishes general conditions that are automatically incorporated into any certificates issued under the proposed rule.

The proposed maximum term for the certificate is five years. The five-year term reflects several considerations. First, comments received during the Commission's consideration of 18 CFR 2.79 indicate that more than two years are required to attract many of the potential sources of new gas supplies. Second, users served by this program do not require more frequent recertification, as their progress toward conversion to alternate fuels in not a consideration under this program. Third, a number of optimistic supply projections have recently been put forward and, if correct, could provide a basis for extending the lengths of certificates. On the other hand, natural gas production is in an evident period of transition and uncertainty. The public interest would not appear to be served by long-term supply commitments, at this time. The Commission seeks comments on the appropriate length of certificates attendant to direct sales.

The Commission proposes to entertain requests for a ten-year term in applications where the users will develop and produce their own reserves. However, the ten-year term will not be available to eligible users who merely acquire reserves-in-place. This longer certificate term is intended to provide eligible users an incentive to develop new natural gas supplies. Again, the Commission solicits views.

Under proposed paragraph (b), a pipeline may apply for a renewal certificate. Such reapplication will be reviewed *de novo*. Thus, an eligible user who enters into a contract for the purchase of direct sale gas for a period of more than five years does so at its own risk. Proposed paragraph (c) provides a six-month grace period to permit delivery of volumes beyond the end of the certificate's term if the producer contract includes a take-or-pay provision.

Proposed § 157.105(d) requires an acceptance of the certificate to be filed only by the interstate pipeline company. The eligible user, the producer, and any nonjurisdictional transporter of the direct sale gas are deemed to consent to the transportation certificate through their execution of the contracts filed with the application. Under proposed paragraph (e) if the gas is diverted to uses other than the eligible uses, the certificate authorization ceases and any further deliveries by the pipeline would be in violation of the Natural Gas Act. While interstate pipelines cannot completely monitor the end-uses of their customers, the sanctions of Natural Gas Act section 21 will apply to any pipeline which willfully and knowingly continues to tranport direct sale gas to a customer who has diverted gas from eligible uses.

Proposed paragraph (f) requires the eligible user to file an annual report within 60 days of the anniversary of the issue date of the certificate. The report will deter possible diversion of gas from eligible uses.

Proposed paragraph (g) requires the interstate and intrastate pipelines transporting direct sale gas to use the same rate methodology that applies to tranportation under section 311(a) of the NGPA. This rate methodology is also used in the recently promulgated emergency purchase regulations (Subpart C of Part 157).

The proposed rule does not require the transportation service to be subject to interruptions prompted by the needs of the pipeline's higher priority customers. The jurisdictional consequences of the Natural Gas Act precluded such a condition from being imposed upon the Commission's previous direct sales program. Because the enactment of the NGPA has insulated

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producers of eligible supplies from possible Natural Gas Act jurisdiction, the Commission invites comments on any appropriate circumstances for interruption of service.

III. Written Comments

Interested persons are invited to submit written comments on the proposed regulations to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should reference Docket No. RM79-18 on the outside of the envelope and on all documents submitted to the Commission. In order that the Commission be able to take into account as many comments as possible, the Commission requests that persons submitting comments assist in three ways. First, persons should identify specifically the section they are addressing. Second, comment should clearly state whether they involve technical, policy or legal matters. Finally, where comments urge a different approach from one presented, specific alternative language should be proposed to the extent possible.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission by March 12, 1979, will be considered prior to the promulgation of final regulations.

The Commission intends to allow an opportunity for the oral presentation of data views and arguments. These proceedings will be held at times and places, to be announced.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.* Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, Natural Gas Policy Act of 1978, Pub. L. 95-621, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 43 FR 46267).

In consideration of the foregoing, it is proposed to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

Section 3.5(f) of Subchapter A of Chapter I, Title 18, Code of Federal Regulations, is amended to read as follows:

§ 3.5 Delegations of final authority.

The Commission authorizes:

* * * * *

(f) The Director of the Office of Pipeline and Producer Regulation or in the Director's absence, the Director's designee to:

(1) Pass upon the following types of applications or amendments to applications: *Provided*, That no formal opposition to the applications or amendments is timely filed with the Commission.

* * * * *

(iv) Applications for temporary certificates for the transportation of natural gas to end-users, pursuant to § 2.79 or § 157.101 of this chapter.

1. Subchapter E is amended by designating § 157.5 through 157.22 as Subpart A—Applications for certificates of public convenience and necessity and for orders permitting and approving abandonment under section 7 of the Natural Gas Act, as amended, concerning any operation, sales service, construction, extension, acquisition or abandonment and § 157.23 through 157.42 as Subpart B—Filings by producers and gatherers of natural gas which are also natural gas companies.

Subpart A—Applications for Certificates of Public Convenience and Necessity and for Orders Permitting and Approving Abandonment Under Section 7 of the Natural Gas Act, As Amended, Concerning Any Operation, Sales Service, Construction, Extension, Acquisition or Abandonment

§§ 157.5 through 157.22 [Redesignated as Subpart A]

Subpart B—Filings by Producers and Gatherers of Natural Gas Which Are Also Natural Gas Companies

§§ 157.23 through 157.42 [Redesignated as Subpart B]

2. Subchapter E is further amended by adding a new Subpart E to read as follows:

Subpart E—Transportation Certificates Under Section 7(c)(2) of the Natural Gas Act

Sec.
157.100 Applicability.
157.101 General rule.
157.102 Eligible uses.
157.103 Application requirements.
157.104 Eligible gas reserves.
157.105 General conditions.

AUTHORITY: Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.* Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, Natural Gas Policy Act of 1978, Pub. L. 95-621, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 43 FR 46267.

Subpart E—Transportation Certificates Under Section 7(c)(2) of the Natural Gas Act

§ 157.100 Applicability.

This subpart implements section 7(c)(2) of the Natural Gas Act and applies to transportation certificates of public convenience and necessity for direct sales of natural gas to certain high-priority users.

§ 157.101 General rule.

(a) *Applications.* Any interstate pipeline, or eligible user on behalf of an interstate pipeline, may file an application as described in § 157.103 for transportation to serve eligible uses as defined in § 157.102.

(b) *Temporary certificates.* Any such application may include a request to be treated also as an application for a temporary certificate and shall be processed by the Commission staff on an expedited basis.

(1) If the application for a temporary transportation certificate is sufficient on its face, a temporary transportation certificate may be issued by the Director of the Office of Pipeline and Producer Regulation pursuant to his authority under § 3.5(f)(1)(iv) of this chapter.

(2) The pipeline may, within 30 days of the date of issuance, file in writing its acceptance or rejection of the temporary certificate. If no acceptance or rejection has been filed within the 30 days, the temporary certificate shall be deemed to have been accepted and shall be effective on the issue date of the order granting such temporary certificate, or such other date prescribed by the Commission.

157.102 Eligible uses.

(a) For the purposes of this subpart, the term "eligible uses" means:

(1) Any use of natural gas certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" under section 401(c) of the Natural Gas Policy Act of 1978; or

(2) Any use of natural gas by a person who uses natural gas in a hospital or school or similar institution as defined in § 281.203(b) (2) and (3) of this chapter.

(b) An "eligible user" is any person who consumes natural gas for an eligible use.

(c) These eligible uses are "high-priority uses" within the meaning of section 7(c)(2) of the Natural Gas Act.

§ 157.103 Application requirements.

All applications pursuant to this subpart must:

(a) Indicate volumes to be transported under the proposed certificate on a peak day, average day and annual basis;

(b) Include a statement by the pipeline that it has capacity sufficient to perform the transportation service without detriment or disadvantage to the interstate pipeline's existing customers who are dependent on the pipeline's general system supply;

(c) Indicate the impact of the proposed transportation on the pipeline's ability to provide systemwide deliveries for requirements defined in § 2.78(a)(1)(i) of this chapter;

(d) Provide a copy of the proposed transportation agreement, indicating the proposed transportation rate together with a breakdown and justification of the proposed rate level to the extent indicated in § 284.106 of this chapter for interstate pipelines or § 284.126 of this chapter for intrastate pipelines;

(e) Include a statement by the distributor that it has capacity sufficient to perform the transportation service without detriment or disadvantage to its other customers.

(f) Describe any facilities that will be constructed in order to provide the services, as well as any other facilities that will be utilized, and specify their location. For purposes of this paragraph, there is no requirement that omission of other filing requirements be justified. For purposes of this paragraph, the following provisions are waived:

(1) 18 CFR 157.13—Form of exhibits to be attached to applications;
(2) 18 CFR 157.14—Exhibits;
(3) 18 CFR Part 159—Fees and annual charges under the Natural Gas Act;
(4) 18 CFR Part 201—Uniform system of accounts for natural gas companies; and
(5) 18 CFR Part 260—Statements and reports (schedules).

(g) Indicate that the proposed end-users of such consumption are eligible uses;

(h) Indicate the total end-use requirements profile for natural gas at the location where the transported natural gas will be used;

(i) Provide a copy of the gas purchase contract with the producer underlying the proposed transportation;

(j) Provide a certified copy, if one has been obtained, of any currently effective determination by a jurisdictional agency under section 503 of the Natural Gas Policy Act of 1978 and Part 274 of this chapter applicable to the natural gas to be transported;

(k) File an affidavit that includes the well number or numbers from which the natural gas will be produced, and either state that the natural gas meets the eligibility requirements of § 157.104, or make application for waiver of such requirements.

(l) If an intermediary participates in the transaction between the eligible user and the producer and charges a fee, indicate the amount of the fee and terms of payment and the intermediary's affiliation, if any, with the producer and/or pipeline;

(m) If either the producer or the eligible user assumes the cost of the construction of any gathering facilities in order to consummate the purchase, provide the cost, terms of payment, ownership and date of construction of the facilities.

§ 157.104 Eligible gas reserves.

(a) *Eligibility test.* No certificate issued under this subpart may authorize the transportation of natural gas which was committed or dedicated, as defined in section 2(18) of the Natural Gas Policy Act of 1978, on November 8, 1978.

(b) *Waiver.* A waiver of the requirement of paragraph (a) may be granted by the Commission upon a showing that such waiver is in the public interest.

§ 157.105 General conditions.

(a) *Term.* (1) Transportation certificates under this subpart may be issued for a term of up to 5 years.

(2) If the natural gas reserves are owned and developed by an eligible user, as determined by the Commission, a certificate may be issued under this subpart for a term of up to 10 years upon a showing that such longer term is necessary to permit the economical development of the reserves.

(b) *Renewal.* Certificates issued under this subpart may be renewed upon reapplication, within 12 months of its expiration.

(c) *Extention of term for take-or-pay users.* If an eligible user is unable to receive natural gas supplies for which it has paid under a take-or-pay provision in the underlying sales contract, the transporting pipelines may file a request for a six-month extension of the certificate authorization. The request shall include a statement of the undelivered volumes and the time necessary to complete delivery thereof. Upon receipt of a letter from the Secretary of the Commission acknowledging a filing for such purposes, the requested extension shall be deemed approved.

(d) *Acceptance of certificate.* Except as provided in subparagraphs (1) and (2) of this paragraph, the certificate shall be void and without force or effect unless accepted in writing by the pipeline within 30 days from the issue date of the order issuing such certificate.

(1) When an application for rehearing of such order is filed in accordance with section 19 of the Natural Gas Act, the acceptance shall be filed within 30 days from the date on which the application for rehearing is denied or deemed to have been denied.

(2) When a petition for review is filed in accordance with the provisions of section 19 of the Natural Gas Act, acceptance shall be filed within 30 days after the final judicial review.

(e) *Termination.* The certificate issued to the pipeline is not transferrable in any manner and shall be effective only so long as the natural gas is

consumed for eligible uses and the pipeline continues the operations authorized by the order issuing such certificate and in accordance with the provisions of the Natural Gas Act, as well as the applicable rules, regulations, and orders of the Commission.

(f) *Annual filing.* The eligible user shall file report, within 60 days of the anniversary of issue date of the certificate, containing:

(1) The total amount of natural gas consumed during the preceding 12 month period,

(2) The end-use of such amounts,

(3) The amount of natural gas consumed from other sources during the certificate period,

(4) The end-use of the natural gas from those other sources together with a list of those other sources, and

(5) The average delivered cost per Mcf paid, itemized by amounts paid to:

(i) The producer,

(ii) Each pipeline and distributor involved in transporting the natural gas, and

(iii) Any other parties.

(g) *Rates and charges.* The rates for transportation by any interstate or intrastate pipelines will be charged in accordance with Part 284 of this chapter.

¶ 32,005 Research, Development and Demonstration (RD&D) Program

44 F. R. 7744 (February 7, 1979).

[Docket No. RM79-16]

RESEARCH, DEVELOPMENT AND DEMONSTRATION (RD&D) PROGRAM

Proposed Regulation Modifying the Time Limit for Commission Action

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission proposes to amend its regulations to allow 120 days, rather that the current 90 days, for Commission action on an application for advance approval of a research, development and demonstration (RD&D) program. In its Opinion No. 30, issued September 21, 1978, the Commission stated it would issue a notice of proposed rulemaking to obtain comments on a proposal by California that the timetable be lengthened.

DATES: Comments due March 15, 1979.

ADDRESS: Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 202-275-4166.

The Federal Energy Regulatory Commission (the Commission) hereby gives notice that it proposes to amend 18 CFR 35.22(d) and § 154.38(d)(5)(iv) as promulgated in Order No. 566[1] to allow 120 days, rather than the current 90 days, for Commission action on an application for advance approval of a research, development and demonstration (RD&D) program. Comments are invited in order to assist the Commission in its review of the proposal.

The Commission requests that commentators discuss the merits of the proposal and alternative means, if any, of realizing its purpose.

Background

In order to receive advance approval of an RD&D program for an upcoming year, an RD&D organization or a jurisdictional company seeking such approval must submit a five year RD&D plan at least 180 days prior to the commencement of the program. Under the Commission's current regulations, 18 CFR 35.22(d) and § 154.38(d)(5)(iv), the Commission must act upon the RD&D plan within 90 days after it is filed.

On June 30, 1978, the Gas Research Institute (GRI) submitted a proposed research and development program which was approved in Opinion No. 30.[2] The People of the State of California and the Public Utilities Commission of the State of California (California) filed a comment in the GRI docket criticizing the short timetable imposed as a result of the 90-day deadline. California suggested that the Commission's review of subsequent GRI applications would be "substantially enhanced by a modest amendment of the Commission's regulations" to allow 120 days for Commission action on an application for advance approval of an RD&D program. In Opinion No. 30 the Commission stated that it would isue a Notice of Proposed Rulemaking to obtain comments on California's proposal.

California, additionally, suggested a schedule for handling GRI's next annual application. Assuming that GRI submits its next application on June 4, 1979 in order to obtain Com-

[1] *Research, Development and Demonstration; Accounting; Advance Approval of Rate Treatment*, Docket No. RM76-17, Order issued June 3, 1977.

[2] *Gas Research Institute*, "Opinion and Order Approving the Gas Research Institute's 1979 Research and Development Program", Docket No. RP78-76, issued September 21, 1978.

mission action by October 1, 1979, California proposed that initial comments and a staff report be filed on July 13, 1979. Reply comments by GRI would be filed on August 3, 1979, and further comments would be filed on August 24, 1979.

The procedure adopted in Docket No. RP78-76 for review of GRI's 1979 program was experimental. In Opinion No. 30 the Commission said that in its Notice of Proposed Rulemaking on extending the time limits for action on RD&D plans it would invite parties to include in their comments suggestions on a procedural schedule to be followed in proceedings on GRI's future applications. Accordingly, such comments are now invited. The Commission notes, however, that comments on procedures to be followed in handling GRI's application are solicited through this Notice of Proposed Rulemaking only so that the Commission will have the comments available when it establishes a procedural schedule after GRI files its next annual application in 1979. This is not a rulemaking to establish a particular procedural schedule. The rulemaking proposed herein only revises the 90-day deadline to 120 days.

PUBLIC COMMENT PROCEDURES

Interested persons may participate in this proposed rulemaking by submitting comments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before March 15, 1979. Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-16), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of a person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours. Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.

In consideration of the foregoing, it is proposed to amend Part 35 and Part 154, Chapter I of Title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

KENNETH F. PLUMB,
Secretary.

§ 35.22 [Amended]

1. Section 35.22 is amended in the first sentence of paragraph (d) by deleting "90" and inserting in lieu thereof "120".

§ 154.38 [Amended]

2. Section 154.38(d)(5) is amended in the first sentence of clause (iv) by deleting "90" and inserting in lieu thereof "120".

¶ 32,006 First Sale of Natural Gas Produced from Prudhoe Bay Unit of Alaska for Transportation Through the ANGTS

44 F. R. 7971 (February 8, 1979).

[Docket No. RM79-19]

FIRST SALE OF NATURAL GAS PRODUCED FROM PRUDHOE BAY UNIT OF ALASKA FOR TRANSPORTATION THROUGH THE ANGTS

Proposed Rulemaking and Statement of Policy

Issued February 2, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed Rulemaking and Statement of Policy.

SUMMARY: The Federal Energy Regulatory Commission (the Commission) hereby gives notice of a proposal to amend Part 271, Subchapter H of its interim regulations promulgated under the Natural Gas Policy Act of 1978 (NGPA). The proposed amendment would permit those involved in the first sale of natural gas produced from Prudhoe Bay, Alaska for transportation through the Alaska Natural Gas Transportation System (ANGTS) to apply for adjustments pursuant to section 502(c) of the NGPA in the event of special hardship, inequity, or an unfair distribution of burdens. This amendment is made with respect to the Commission's declining to exercise its discretion under section 110 of the NGPA to permit applications for additions to the maximum lawful price for costs born by the seller of such gas. The Commission also gives notice of a proposal to promulgate a statement of policy under the Natural Gas Act that, absent a showing that the public convenience and necessity would otherwise be served, the purchase of natural gas from Prudhoe Bay, Alaska for transportation through the ANGTS should be of processed gas capable of immediate entry into the transportation system. Therefore, the Commission will approve only those applications for certificates of public convenience and necessity to construct the ANGTS or for the transportation or sale of gas transported through the ANGTS, which do not require the assumption by the applicant or subsequent purchaser of processing or other related costs save to the extent such costs are allowed pursuant to Commission action taken under its regulations permitting adjustments made under section 502(c) of the NGPA.

DATES: Notice of intent of participate, by February 15, 1979. Written comments filed and served, by March 5, 1979. Reply comments filed and served, by March 19, 1979.

ADDRESSES: All filings should reference Docket No. RM79-19 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. All comments and reply comments to be served pursuant to address supplied on the service list.

FOR FURTHER INFORMATION CONTACT:

John Adger, Director, Alaska Natural Gas Project Office, Federal Energy Regulatory Commission, 941 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-3827.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is considering an amendment to its interim regulations implementing the Natural Gas Policy Act (NGPA), 43 FR 56448, December 1, 1978 and the establishment of a policy concerning the recovery of certain "production-related" costs as defined in the NGPA. The amendment to the regulations deals exclusively with first sales of natural gas produced from the Prudhoe Bay Unit of Alaska for transportation through the Alaska Natural Gas Transportation System (ANGTS).[1] The policy state-

[1] Pursuant to the Department of Energy Organization Act, 42 U.S.C.A. 7101 *et seq.* (Supp. 1977), most of the powers formerly exercised by the FPC were transferred to the Commission. By delegation order dated December 5, 1977, the Secretary of Energy transferred to the Commission all necessary powers respecting the ANGTS. 42 FR 61491 (December 5, 1977).

ment reflects the public's interest in the matter of establishing responsibility for bearing production-related costs for that gas.

The policy sets forth the general proposition that the recovery of any "production-related" costs by those making applications for certificates of public convenience and necessity under the Natural Gas Act are restricted to those costs permitted by the Commission pursuant to an adjustment granted under section 502(c) of the NGPA in the event of special hardship, inequity, or an unfair distribution of burdens. The policy which is proposed would apply only to certificates involving the purchase or transport of natural gas produced from Prudhoe Bay for transportation through the ANGTS applied for pursuant to the Natural Gas Act.

The proposal is within the Commission's discretion under section 110 of the NGPA. Our decision is also based upon the Natural Gas Act (NGA) 15 U.S.C. 717 *et seq*; the Alaska Natural Gas Transportation Act of 1976 (ANGTA) (15 U.S.C.A. 719 *et seq.*) (Supp. 1978) and the *Decision and Report to Congress on the Alaska Natural Gas Transportation System* submitted to the Congress by the President.[1]

The Commission solicits opinions, data, and views from interested parties and the general public on the Commission's assessment of the public interest in the matter of assigning responsibility for conditioning the Prudhoe Bay gas pipeline entry. The Commission also solicits comments on the mechanisms proposed to implement that assessment.

A. Background

The ANGTA represents a legislative substitution of a Presidential decision with Congressional approval in lieu of the ongoing Federal Power Commission procedure regarding construction of the ANGTS. The ANGTA also contained specific requirements for the contents of that decision. The *Decision*, forwarded to and approved by the Congress in late 1977, was the product of the process set out in the ANGTA.

The facilities comprising the ANGTS were identifed specifically in the *Decision*.[2] However, certain questions important to the implementation of the selected system remained for future resolution. Paramount was the question of a field price for the gas. As noted in the *Decision*:

> Final financing for an Alaska natural gas transportation project cannot be arranged until the producer-owners of the Prudhoe Bay gas execute sales contracts. Without such contracts, no gas can be transported, and financing consequently would be unobtainable. Producers cannot be expected to negotiate sales contracts until a price has been established with a reasonable degree of certainty. If this project is to proceed expeditiously, the field price of the gas should be established as soon as possible. (*Decision* at 44)

The maximum lawful price for Prudhoe Bay gas was established by section 109 of the NGPA, thereby overcoming the disability referred to and providing the opportunity for the negotiation of sale contracts for the Prudhoe Bay gas.

Other concerns are also important, including the assignment of responsibility for processing the gas prior to injection into the ANGTS. The Commission's amendments and statement of policy herein proposed are designed to implement the NGPA, the ANGTA, and the *Decision*, and thereby to resolve some residual issues and provide a climate for the rapid conclusion of contract negotiations.

B. Issues for Commission Consideration

One of the remaining issues affecting the contracting process relates to conditioning the gas for entry into the ANGTS. There are two questions: (1)

[1] Executive Office of the President, Energy Policy and Planning, *Decision and Report to Congress on the Alaska Natural Gas Transportation System* (September 1977) [hereinafter cited as *Decision*]. Issued pursuant to section 7 of the ANGTA, 15 U.S.C. 719c (1976), and approved by Joint Resolution of Congress, H.R. J. Res. 621, Pub. L. No. 95-158, 91 Stat. 1268 (1977), the *Decision* has the full force of law.

[2] For example, section 3 of the *Decision* states at page 13, "The facilities which are to be covered are those in the U.S. which are adequate for a throughput of up to 2.4 bcfd and are included in the revised Alcan filing submitted to the Federal Power Commission (FPC) on March 8, 1977."

Who is to bear the responsibility for the construction and operation of the necessary conditioning facilities; and, (2) what costs, if any, for conditioning should be permitted to be passed through to the consumer?

1. RESPONSIBILITY FOR THE CONDITIONING FACILITIES.

The responsibility for preparing the Prudhoe Bay gas for entry into the ANGTS has been an issue throughout the consideration of the system. It has been obvious that processing and conditioning facilities would be required in order to condition the gas for transportation.[4] None of the three gas pipeline proposals which were presented to the Federal Power Commission provided for the construction and operation of such facilities: all three assumed that the facilities were the responsibility of the producers. Prudhoe Bay producers, on the other hand, argued that the required "* * * conditioning steps—lowering carbon dioxide content, providing high pipeline inlet pressure, chilling, providing extremely thorough water removal, and maintaining close control of condensable hydrocarbon content—are all designed to minimize the investment and operating cost of the pipeline" and should therefore be part of the gas pipeline system.[5]

The question of whether the processing facility is included in the ANGTS was answered in the *Decision* in the negative. The *Decision* in Section 2 ("Description of the Nature and Route of the Approved System") stated: "The proposed Alcan pipeline will commence on the discharge side of the gas conditioning plant facilities in the Prudhoe Bay Field." (*Decision* at 6) Additionally, the system description in Section 3 states that the first compressor station for the ANGTS will be located 75 miles after the point of commencement of the system. (*Decision* at 17) The necessary conclusion is that the gas will enter the ANGTS compressed to its maximum allowable operating pressure. As chilling to prevent degradation of the permafrost is to be done at compressor stations (*Decision* at 17), there is also the inference (given the location of the first compressor station) that the gas is to leave the conditioning plant sufficiently chilled to be transported over the first 75 miles of permafrost without warming to a temperature above the freezing point of water. Finally, there is the explicit reference that "[t]he facilities which are to be covered are those in the U.S. which * * * are included in the revised Alcan filing submitted to the Federal Power Commission (FPC) in March 8, 1977." (*Decision* at 13) The facilities provided in that filing assume that the gas entering the system will have been conditioned to a certain quality, and compressed and chilled prior to entry.[6]

2. ALLOWANCES FOR CONDITIONING COSTS

Having established that the processing facility would not be part of the ANGTS, that does not determine whether the producers or the pipeline should build the plant or who should pay for its operation. Therefore, the second principal issue which the Commission must consider is whether gas consumers should bear any portion of the costs of preparing the gas for pipeline entry. The Commission must ad-

[4] Federal Energy Regulatory Commission, *Comments on the "Decision and Report to Congress on the Alaska Natural Gas Transportation System"*; 19-34 (October 1977) [hereinafter cited as *Comments*].

[5] *See, e.g., Natural Gas Pipeline from Alaska: Joint Hearings Before the Commerce Subcomm. on Energy and Power of the House Comm. on Interstate and Foreign Commerce and the Interior Subcomm. on Indian Affairs and Public Lands of the House Comm. on Interior and Insular Affairs*, 95th Cong., 1st Sess., Ser. No. 95-79, at 446 (1977) (statement of L. G. Rawl, Executive Vice-President, Exxon, U.S.A.) [hereinafter House Hearings].

[6] Alcan Pipeline Project 48" Alternative Proposal, Docket No. RM77-6. The revised Alcan filing describes a system which would transport natural gas processed to the following standards: (1) 1% carbon dioxide by volume; (2) 0.6% nitrogen by volume; (3) 1138 Btu/cuft gross heating value; and (4) a hydrocarbon dew point of −10° F at 1000 psi. (Alcan Pipeline Project 48" Alternative Proposal at § 3, p. 3; Docket No. RM77-6). This revised filing referenced an initial filing in which the following additional specifications were enumerated: (1) a maximum water content of 0.2 pounds per million cubic feet; (2) a sulphide content of no more than 0.25 grains per 100 cubic feet; and (3) a total sulphur content of 10 grains per 100 cubic feet. Alcan Pipeline Co., FPC Gas Tariff, Original Vol. 1, Exhibit No. AP-16, at Original Sheet No. 112 (Docket No. CP75-96, *et al.*).

dress this issue in deciding whether to allow producers to include in the price of the gas costs over and above the maximum lawful price; or whether any of such charges, if paid by purchasers of the gas, could be passed through to consumers.

The Decision, in relevant part (Section 6—Pricing of Alaska Gas), took note of the difficulty in determining a cost-based price for the Prudhoe Bay gas because of its association with oil in the reservoir. It also observed that the Administration's proposed National Energy Act (NEA), then before Congress, would obviate that difficulty by shifting from cost-based pricing to a series of price ceilings determined by statute. The *Decision* then called "for enactment of a gas pricing approach similar to that contained in the National Energy Plan." (Decision at 46)

An amended version of the National Energy Act had passed the House of Representatives and was being considered by the Senate at the time of the *Decision*. That version allowed for possible increases, if allowed by the Commission, in the ceiling prices established by the statute to cover costs of gathering, conditioning, and compressing the gas for pipeline entry.

The Report which accompanied the *Decision* contained a discussion of the economic viability of the ANGTS.[7] Because of the possibility that the Commission might provide some allowance for costs of gathering, conditioning, and compression, that discussion used a range of 0 to 30 cents per MMBtu (1975 dollars) for a potential add-on in estimating the "city gate" or wholesale price of the gas.[8] However, the *Decision* clearly left determination of the appropriate amount of any such allowance to the discretion of the Commission.[9]

In its comments on the *Decision*, the Commission addressed the question of possible allowances for costs of gathering and conditioning.[10] The Commission recognized that a field price would have to be established either through legislation or through ratemaking proceedings before any determination could be made with regard to possible allowances for gathering and conditioning. As the Congress had not completed its deliberation on the National Energy Act, at the time of the Commission's comments on the *Decision*, the Commission could only discuss the factors it might consider if called upon to reach a determination regarding possible allowances. (*Comments* at 34-35)

The comments noted that although there will be a variety of costs associated with producing, gathering, and conditioning the gas for pipeline entry, there will also be substantial revenues available from these activities to offset those costs. Since the Prudhoe Bay gas is produced in association with oil, the Commission's comments contemplated that costs could be allocated among sales of gas, oil and natural gas liquids (NGL's), and looked to the gas sales contracts for the initial division of revenues and costs between producers and transporters. The Commission could then determine if an allowance for costs of processing and conditioning was warranted.

The NGPA, as finally passed by Congress, provided both a maximum lawful price for the first sale of Prudhoe Bay gas (section 109) and Commission discretion regarding treatment of "certain production-related costs" (section 110). The legislative history of section 110 makes it clear that, while

[7] *See Report* accompanying the President's *Decision*, at 93-98. While not adopted by the Congress in its joint resolution on the *Decision*, the *Report* was submitted to them with the *Decision*. It may thus be considered as relevant legislative history. *See Midwestern Gas Transmission Co. v. FERC*, No. 78-1753, slip op. at 11-12, n. 23 (D.C. Cir., Nov. 2, 1978)

[8] The actual costs of gathering and conditioning were estimated to be about 30 cents per MMBtu (1975 dollars). The range presented was intended to cover the spectrum of possibilities between a Commission determination that no add-on be provided and a determination that all these costs should be passed on to gas consumers.

[9] *See, e.g., Decision* at 95: "When the cost of service price of the Alcan project is added to a wellhead price of $1.45 to $1.75 per mmbtu (*depending on the amount the FPC will allow producers for their processing costs*), the wholesale or "city gate" price of the gas should be about $2.50 to $2.80 per mmbtu in constant 1975 dollars." (emphasis added). *See also* the statements of DOE Secretary Schlesinger in discussing the Decision before the House, House Hearings, supra note 5, at 219, 224-26, 234, 280-81.

[10] *Comments* at 19-34.

the Commission's authority to permit producers or other first sellers to charge an amount in excess of the maximum lawful price is discretionary, this authority should, when possible, be exercised in light of "prevailing industry practice."[11]

"[P]revailing industry practice" as to functions usually performed by the producer can be determined by reference to existing contracts and sales for those areas having a history of natural gas production and sales. It was on this basis that the Commission's interim regulations were structured. (43 FR 56490) There is, however, no such history for Prudhoe Bay, since the production from that area has never come under contract. For this reason, the Commission's discretion to consider the add-on of production-related costs for this producing area is not bound by considerations which prevailed for conventional producing areas.

C. Commission Assessment of the Public Interest

The Commission believes that there is adequate information in the *Decision*, the Report accompanying it, and the legislative history to draw some preliminary conclusions regarding responsibility for the gas conditioning facilities at Prudhoe Bay and the need for any special allowances to the producers for the costs of construction and operation of those facilities. The Commission in this section outlines these conclusions and puts forward specific proposals to achieve the distribution of costs and benefits which conform to these conclusions.

1. Responsibility for the Conditioning Plant

It is the Commission's view that the Prudhoe Bay producers should be responsible for the construction and operation of the required conditioning facility. Providing the ANGTS with pipeline quality gas is the responsibility of the producers.[12] Therefore, the public interest will best be served if the producers bear these costs.[13] This conclusion is based on the premise that the producers will contract with purchasers for the sale of Prudhoe Bay gas at not less than the maximum lawful price set by section 109 of the NGPA. If the parties agreed to a sales price lower than the section 109 (NGPA) ceiling with the pipeline paying for some processing costs, the Commission would not necessarily oppose such and outcome provided the total price paid for pipeline quality gas did not exceed the section 109 (NGPA) price.[14] In any event, the financial responsibility for the construction and operation of the plant facilities rests with the producers.

An additional consideration in this determination is the risk of reduced gas deliverability and the potential for reducing this risk. Producer responsibility for the processing facilities is one answer. The ANGTS was designated for a throughput of up to 2.4 billion cubic feet per day. (*Decision* at 13) That these facilities will be efficiently used, and that natural gas will be available to ensure that efficient use, is a proper concern of the Commission. There has been a question as to whether the producers might be able to provide some type of throughput

[11] 124 Cong. Rec. H13118 (Daily ed. Oct. 14, 1978). (Statement of the Hon. John D. Dingell.)

[12] *See* statement of Secretary Schlesinger testifying on the *Decision* in *Alaska Natural Gas Transportation System: Hearings before the Senate Comm. on Energy and Natural Resources*, 95th Cong., 1st Sess., No. 95-73, at 12-13. Similar treatment to that proposed here was afforded in the Commission's interim regulations implementing section 110 of the NGPA, 43 FR 56489-92 (Dec. 1, 1978).

[13] To the extent the pipeline were called upon to finance the plant, pay for its operation, or expend funds above the section 109 (NGPA) price to obtain pipeline quality gas, there might be an adverse effect on the financability of the project or the marketability of the gas to the consumer. Even the possibility of such an impact would be detrimental and alien to the public good.

[14] The only consideration to be added is with respect to the incremental pricing provisions of section 203(a)(8) of the NGPA. The Commission welcomes the submission of comments on this point.

guarantee to reduce the pipeline's and the consumer's exposure to the risk of reduced deliverability.[15] The Commission believes that producer responsibility for the gas conditioning facility would provide some deliverability protection. Should underutilization of a producer-owned facility result from reduced deliverability from the Prudhoe Bay field, the producers, who have the ability to explore for new sources of gas, will have an additional incentive to find and produce such gas as is necessary to maximize the use of the plant. If this result occurs, greater volumes available for transportation will make for a more efficient operation of the ANGTS.

The Commission believes that the specific language of the *Decision* in its description of the ANGTS and the potential for ensuring the system some form of deliverability protection forms the basis for a definitive Commission finding that the conditioning facilities should be the responsibility of the producers. If the producers should engage some third party to perform the conditioning function, the Commission must be satisfied that deliverability protection similar to direct producer responsibility is provided to gas consumers.

2. COSTS OF GATHERING AND CONDITIONING

In issuing proposed regulations to implement section 110 of the NGPA for lower-48 producing areas, the Commission included quality standards which would have to be exceeded in order for the Commission to consider an allowance for production-related costs above the NGPA maximum lawful price (43 FR 56574-77 (Dec. 1, 1978)). These standards were based upon experience in the lower-48 producing areas. For gas sales made from Prudhoe Bay there is no such experience. In lieu thereof, we have the *Decision*, its description of the system, and its references to the filings containing appropriate quality standards to rely on. (*See* note 6 above.) For this reason, the Commission believes that the quality standards used for the lower-48 are inapplicable for gas delivered to the ANGTS.

As with the Commission's interim regulations for the lower-48 producing area, the Commission believes that costs of delivering "pipeline quality gas" to the ANGTS should be covered by the first sale price ceilings which are provided by the NGPA. With respect to Prudhoe Bay, it is the *Decision* and not prevailing industry practice that determines the quality standards. (*Supra*, note 6) Therefore, the Commission declines to exercise its discretion under section 110 of the NGPA to permit an adjustment for production-related costs of the Prudhoe Bay gas.

We do not believe on the basis of available information, that a refusal to allow production-related costs in excess of the ceiling price established in section 109 of the NGPA will work any hardship on the producers. Such information as is available suggests that the NGPA's section 109 price is adequate to compensate the producers for the costs of producing, gathering and conditioning the gas for sale to the ANGTS at the prescribed standards. The Department of the Interior, as part of a study of alternative transportation systems completed in December of 1975, evaluated the incremental costs of producing and conditioning the gas for sale.[16] That study estimated those costs, including an appropriate return on equity investment, to be 47 cents/MMBtu (1975 dollars). Additionally, the Federal Power Commission, in its *Recommendation to the President*, estimated the costs of gathering and conditioning at about 50 cents/MMBtu (1975 dollars).[17] If these estimates of costs are close to being correct, then the $1.45 per MMBtu (1977 dollars) provided by section 109

[15] *See, e.g.*, Federal Power Commission, *Recommendation* to the President, at I-57, XII-7, 8 (May 1, 1977) [Hereinafter FPC Recommendation]. For field performance, the producers' response to this issue has been that any deliverability guarantee on their part would be essentially useless because the rate of production is controlled by the Alaska state conservation authority. The producers reiterate their assertion that any performance guarantee for the facility, like the facility itself, is not their responsibility.

[16] U.S. Dept. of the Interior, *Alaska Natural Gas Transportation Systems, A Report to the Congress Pursuant to Public Law 93-153* (Dec. 1975).

[17] FPC Recommendations at XII-33, 34 n. 52.

of the NGPA would appear more than adequate to cover the incremental costs associated with gas sales, plus a reasonable profit.[18] The Commission solicits opinions, data and views regarding the costs of producing and conditioning this gas and the adequacy of the section 109 (NGPA) price to cover the incremental costs of gas production and conditioning for transportation in the ANGTS without inflicting hardship, creating inequity, or unfairly distributing to producers a burden.

D. SPECIFIC PROPOSALS.

In this section, specific mechanisms are proposed in order to implement the policy expressed herein for the purpose of protecting the public interest in the assignment of responsibility for the construction and operation of the processing facilities. These mechanisms are: (1) An amendment to the presently effective interim regulations to make section 502(c) of the NGPA applicable to Prudhoe Bay gas to provide an opportunity for relief if the Commission's perceptions of the distributions of production-related costs and benefits associated with producing and conditioning the Prudhoe Bay gas are not borne out; and (2) a policy statement under the NGA to govern certain aspects of future pipeline certification proceedings. The latter is required in order to make clear the Commission's interpretation that the facilities, and their associated costs, required to bring the gas to pipeline quality are the responsibility of the producers and not the pipeline company purchasers and transporters of the gas. The rationale for this interpretation and its public interest basis has been discussed above. We look to the submissions of opinions, data and views in response to this notice.

The proposed amendment would amend the Commission's current interim regulations to make the section 502(c) adjustment procedures available to those engaged in the sale and purchase of natural gas produced from Prudhoe Bay for transportation through ANGTS. The regulations would then provide for an adjustment if a special hardship, inequity, or an unfair distribution of burdens resulted.

Section 110 grants the Commission discretion to allow a price in excess of the maximum lawful price for permissible production-related costs borne by the seller. The scope of this statutory discretion does not reach the case of a sale at the maxumum lawful price where there are production-related costs but they are not borne by the seller. This raises the possibility that untreated Prudhoe Bay gas may be sold at the maximum lawful price.[19] Such a sale of untreated Prudhoe Bay gas would have several undesirable consequences. It would shift gas processing costs from producers to consumers, thereby increasing the city-gate price of the gas and adversely affecting its marketability. In addition, certain production-related costs required for oil production, attendant to the production of the Prudhoe Bay gas but not related to gas sales, could be improperly shifted to the gas purchaser. (See *Comments* at 19-34.)

It is the Commisson's opinion that such a shift to the consumer of production-related costs would not be in the public interest because it would materially increase the cost of this gas to the consumer. For these reasons, the Commission declines to exercise its discretionary authority under section 110 to permit a first seller to charge a price in excess of the maximum lawful price permitted under section 109 for production-related costs.

Although the Commission's "conditional" certificate for the building of the ANGTS was issued pursuant to sections (5)(A)(2) and 9 (a) and (b) of the ANGTA, a final certificate authorizing construction and operation must be issued pursuant to section 7 of the Natural Gas Act (NGA), 15 U.S.C. 717f(c).[20] In assessing the certification of the project which the statute re-

[18] In this regard, the Commission notes that the $1.45 maximum level price applicable for the first sale of this gas, adjusted for inflation to April of 1979, is $1.672 per MMBtu.

[19] *See, e.g.*, 124 Cong. Rec. S16257 (daily ed. Sept. 27, 1978) (exchange between Senators Gravel and Jackson).

[20] Order Vacating Prior Proceedings and Issuing Conditional Certificates of Public Convenience and Necessity, issued December 15, 1975, in Docket Nos. CP78-123, *et al.*

quires, the Commission must consider the public convenience and necessity. A necessary part of this consideration is the assessment of the financeability of the ANGTS and the marketability and availability of the gas to be transported through it. The proper distribution of the processing costs impacts these considerations.

Mindful of the considerations inherent in the President's *Decision* on its approval of the ANGTS, and pursuant to the Commission's statutory authority,[21] the Commission intends to implement a policy that in its consideration of certificates for the construction of the ANGTS, or for the purchase or transportation of gas through the ANGTS, no cost of construction, purchase, or transportation which includes costs of processing the Prudhoe Bay gas will be certificated absent a determination made under section 502(c) of the NGPA that the cost is one properly allocable to the price of the gas. Such a policy will allocate production-related costs in a manner consistent with the Commission's view of the public interest, and will enhance the financeability of the ANGTS, assist marketability of the gas involved, and avoid the complications of incremental pricing. Such a policy is not inconsistent with congressional dictates which touch upon this gas and its transportation through the ANGTS.[22]

The policy which the Commission proposes would apply only to certificates which involve the purchase or transportation of natural gas produced from the Prudhoe Bay Field for transportation through the ANGTS. The issuance of the certificates will proceed according to the prescriptions of the NGA.

E. Written Comment Procedures

The Commission invites interested persons to submit written data, views, and other information concerning the matters set forth in this notice. An original and 14 copies should be filed by March 5, 1979. Comments should be submitted to the Federal Energy Regulatory Commission, Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426 and should reference Docket No. RM79-19. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NE., Washington, D.C., during regular business hours.

Because of the complexity and importance of the issues presented in this notice, the Commission intends that those participating in this proceeding should serve their comments on other participants, and have an opportunity to respond to the initial comments made in response to this notice. In order for this to take place, any participant intending to file initial comments to this notice shall notify the Secretary of the Commission in writing on or before February 16, 1979 of the intent to participate. A service list will then be prepared and mailed to those who have stated an intention to participate. The initial comments shall be filed with the Office of the Secretary as stated above. In addition, each party shall serve their initial comments by March 5, 1979 to those of the service list. Reply comments are to be filed with the Office of the Secretary in accordance with the above procedures by March 19, 1979, and

[21] Section 9 of the ANGTA provides that when any agency action is "necessary or related to the construction and initial operation of the approved transportation system," and that action "requires a certificate, right-of-way, permit, lease, or other authorization," the Commission must act at the earliest practicable date. The availability of an adequately processed gas supply for transportation through the system is obviously directly necessary and related to the construction and initial operation of the ANGTS. The processing facilities of Prudhoe Bay will not be part of the transportation system itself, but the building and operation of these facilities, and indeed the executing of related gas sales contracts, require the Commission to take the action proposed herein. *See Decision* at 44.

[22] Section 601(c) of the NGPA, in its treatment of the limitations placed upon the NGA certification authority of this Commission is not germane. That section speaks only to the denial of a certificate based on the maximum lawful price paid for the gas, inclusive of that permitted under section 110. It does not address the issue posed here: the assumption by a pipeline of processing costs attendant to a purchase and sale of natural gas of less than pipeline quality.

shall be served upon parties listed on the service list by the same date.

In providing proper service of the initial comments and any reply comments, attention is directed to the regulations of the Commission found at 18 CFR 1.17(b) [1977] which permits service by mail. In addition, those who provide comments are directed to the subscription and verification provisions found at 18 CFR 1.16 [1977].

In order that all interested parties may be apprised of this matter, the Commission orders that the Secretary, in addition to publishing this notice in the FEDERAL REGISTER, shall serve copies of the same to all parties of record in Docket Nos. CP78-123, CP78-124, CP78-125, and RM78-12, said service to be accomplished pursuant to 18 CFR 1.17 [1977].

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350 (1978); Department of Energy Organization Act, Pub. L. No. 95-91; Executive Order No. 12009, 42 FR 46267; DOE Delegation Order No. 0204-8, 42 FR 61491; Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. 719, *et seq.*; President's *Decision and Report to Congress on the Aluska Natural Gas Transportation System*, approved by joint resolution, Pub. L. No. 95-158, 91 Stat. 1268 (1977); Administrative Procedure Act, 5 U.S.C. 553.)

In consideration of the foregoing, the Commission proposes to amend Part 2, Subchapter A and Subpart K, Part 271, Subchapter H of Chapter I, Code of Federal Regulations as set forth below.

By the Commission. Commissioner Sheldon voted present.

KENNETH F. PLUMB,
Secretary.

(1) Part 2, Subchapter A of Chapter I, Title 18 Code of Federal Regulations is amended by adding new § 2.101 to read as follows:

§ 2.101 Policy respecting consideration of certain certificates applied for pursuant to the Natural Gas Act and involving gas to be transported through the Alaska Natural Gas Transportation System.

In any proceeding involving the approval of applications for certificates of public convenience and necessity, whether for the construction of the Alaska Natural Gas Transportation System or for the purchase or transport of gas through that system, it will be the general policy of the Commission, absent a showing that the public convenience and necessity would otherwise be served, that the purchase of natural gas from Prudhoe Bay, Alaska for transportation through the Alaska Natural Gas Transportation System should be of processed gas which is capable of immediate entry into the transportation system; and therefore, the Commission will approve only those applications for certificates of public convenience and necessity which do not require the assumption by the applicant or subsequent purchaser of processing or other related costs save to the extent such costs are allowed pursuant to Commission action taken under § 271.1106 of its regulations.

(2) Section 271.1100 of Subpart K, Part 271 of Subchapter H of Chapter I, Title 18 Code of Federal Regulations is amended in paragraph (b) to read as follows:

§ 271.1100 Applicability.

* * * * *

(b) *Exclusions.* Sections 271.1104 and 271.1105 shall not apply to any natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

(3) Section 271.1106 of Subpart K, Part 271 of Subchapter H of Chapter I, Title 18 Code of Federal Regulations is amended to read as follows:

§ 271.1106 Adjustments.

Pursuant to section 502(c) of the NGPA, any person may apply to the commission for an adjustment on the grounds that the operation of §§ 271.1100)b) or 271.1105 results in special hardship, inequity, or an unfair distribution of burdens to such person.

¶ 32,007 Certain Sales of Natural Gas by Intrastate Pipelines

44 F. R. 7976 (February 8, 1979).

[Docket No. RM79-20]

CERTAIN SALES OF NATURAL GAS BY INTRASTATE PIPELINES

Further Notice of Proposed Rulemaking and Public Hearing

Issued February 5, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Further notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is seeking further written comments on its revised proposed regulations implementing section 311(b) of the Natural Gas Policy Act of 1978. Section 311(b) provides that the Commission may, by rule or order, authorize sales of natural gas by intrastate pipelines to interstate pipelines or local distribution companies served by interstate pipelines.

DATES: Written comments to be filed by February 21, 1979; public hearing to be held February 20, 1979.

ADDRESSES: Comments and requests to participate in the public hearing should be addressed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Romulo L. Diaz, Jr., Deputy Assistant General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-1790, or Howard Kilchrist, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4539.

SUPPLEMENTARY INFORMATION:

I. Background

Section 311(b) of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. 95-621, November 9, 1978, provides that the Federal Energy Regulatory Commission (Commission) may, by rule or order, authorize any intrastate pipeline to sell natural gas to any interstate pipeline and any local distribution company served by an interstate pipeline. Section 311(b) also sets forth certain requirements relating to rates and charges, duration and other matters in connection with the sales, and states that sales authorized under section 311(b) are subject to terms and conditions prescribed by the Commission.

On November 13, 1978, the Commission adopted a notice of proposed rulemaking (43 FR 53270, November 15, 1978) in Docket No. RM79-3, proposing interim regulations to implement the NGPA. In that document, the Commission requested comments on proposed regulations implementing section 311(b). Although most of the regulations in that proposal were to become effective on December 1, 1978, the Commission proposed not to make the new Subpart C of Part 284, implementing section 311(b), effective until after the current winter heating season. The purpose of delaying the effectiveness of the section 311(b) rule was to permit a smooth transition between the Commission's emergency exemption program under section 7(c) of the Natural Gas Act, and the implementation of the NGPA provisions permitting sales by intrastate pipelines to interstate pipelines and local distribution companies.

In this notice of proposed rulemaking, the Commission requests further data, views and comments with respect to the implementation of section 311(b) and also invites participation in a public hearing on the proposal. Comment procedures and information concerning the hearing are set forth below.

II. Summary of the Proposed Regulation

As proposed, Subpart C of Part 284 would generally permit intrastate pipelines to sell natural gas to interstate pipelines and to local distribution companies served by interstate pipelines, in accordance with the provisions of the subpart. These sales

would take place without prior Commission approval, but as required by section 311(b)(4) of the NGPA and § 284.145(b) of the proposed regulations, would be subject to interruption to the extent that natural gas subject to the sale is required by selling pipeline to provide adequate service to the pipeline's customers at the time of the sale.

Sales would be limited to two years' duration under proposed § 284.145(a) and could be extended for periods of up to two years each if not disapproved by the Commission after opportunity for oral and written comments. The Commission could also modify the terms of a proposed extension and impose upon sales or extensions terms and conditions it deemed appropriate and in the public interest. Upon complaint or its own motion, the Commission could also terminate a sale after making certain findings enumerated in section 311(b)(6) of the NGPA.

Section 284.145(c) of the reguations states that no sales under Subpart C may involve natural gas acquired by the intrastate pipeline solely or primrily for the purpose of resale under section 311(b).

Section 311(b)(2) sets forth the statutory requirements relating to rates and charges by intrastate pipelines for sales to which these rules apply. Rates and charges must be "fair and equitable" and may not exceed the sum of (1) the pipeline's weighted average acquisition cost of natural gas; (2) an amount determined by Commission rule to be necessary to provide reasonable compensation for services and a reasonable opportunity for profit; and (3) an adjustment for current costs incurred under certain circumstances due to the sale. The Statement of Managers accompanying the Conference Report states that the conferees did not intend that the selling pipeline make a profit on the purchase and sale aspects of the transaction (H.R. Rep. No. 95-1752, p. 108).

In the November 13 proposal, the Commission proposed a definition of "weighted average acquisition cost of natural gas" which would have used volumes of gas acquired during a 12-month period (ending no more than 90 days prior to commencement of deliveries pursuant to the sale) and the prices paid for those volumes on the last day of the 12-month period. Under that formula, the weighted average acquisition cost of natural gas would have been fixed for the duration of a Subpart C sale as of a time up to 90 days prior to the commencement of deliveries.

The Commission received a number of comments which argued that the regulations should provide a formula that would permit a pipeline to charge a price determined on the basis of a constantly updated acquisition cost. In addition, the conferees stated that the determination of the weighted average acquisition cost was meant to be a contemporaneous determination involving the cost of gas at the time it is acquired and resold and that the customers of the selling pipeline shall be in no worse position as to price or supply. (H.R. Rep. No. 95-1752, p. 108). In view of these comments and the statements of the conferees, the Commission has revised its proposal. The new proposed § 284.143 would provide for a monthly determination of the weighted average acquisition cost of natural gas. For any calendar month in which deliveries pursuant to Subpart C occurred, the weighted average cost would be computed by (1) determining the quantities (in MMbtu's) of gas acquired from each source of supply during a 12-month period ending no more than 90 days before the beginning of the month; (2) multiplying the MMbtu's attributable to each source of supply by the most recent price actually paid with respect to each source; and (3) dividing the sum of the products computed in (2) by the sum of the MMbtu's determined in (1). Thus, the calculation of the weighted average cost would be revised monthly on the basis of the most recent prices paid. This moving average approach would enable the intrastate pipeline to reflect the latest prices paid while at the same time avoiding the substantial fluctuations that would occur under monthly computations.

The intrastate pipeline's weighted average acquisition cost of natural gas is one of the three components of the permissible rates and charges for a sale under Subpart C. The pipeline may add to that cost, as provided in § 284.144(a)(2), an amount to recover the costs of gathering, treating, proc-

essing, transporting and delivering the gas as provided in § 284.123 of Subpart B of Part 284 (Interim Regulations, 43 FR 56628-56629, December 1, 1978). Under § 284.123(b), an intrastate pipeline may base its rates upon the methodology and cost used (1) in designing its rates to recover the cost of gathering, treatment, processing, transportation, delivery or similar service (including storage) included in its firm sales rate schedules for city-gate service on file with a state regulatory agency; or (2) in determining the allowance permitted by an appropriate state regulatory agency for city-gate service by the intrastate pipeline. The pipeline may elect to use the rates contained in a transportation rate schedule for intrastate service on file with the state regulatory agency which the pipeline determines covers service comparable to service under Subpart B. Instead of any of these methods, an intrastate pipeline may file proposed rates with the Commission, with information showing the rates to be fair and equitable, and may commence service using those rates, subject to refund. The Commission received comments stating that if intrastate pipelines were not permitted to make a profit on sales under section 311(b), they would have no incentive to enter into these transactions. As noted above, however, the conferees stated that they did not intend that the purchase and sale aspects of the transaction produce a profit for the selling pipeline. By incorporating the Subpart B computation of charges for services in connection with a Subpart C sale, however, the Commission intends to afford intrastate pipelines the same compensation and opportunity for reasonable profit as would be afforded in a wholly intrastate transportation transaction and to satisfy the requirements of section 311(b)(2)(B) of the NGPA.

The third component of the rates and charges permissible in Subpart C sales is the adjustment described in section 311(b)(2)(C) of the NGPA and § 284.144(b) of the proposed regulations. The adjustment is intended to offset any contemporaneous increase in the weighted average acquisition cost of gas that a pipeline would incur to acquire gas under existing contracts as a result of entering into sales under Subpart C. The adjustment may be included in the sales price with respect to gas which (1) is acquired under an existing contract; (2) is in excess of quantities the pipeline would otherwise have acquired; and (3) the price of which exceeds the pipeline's weighted average acquisition cost of gas. If natural gas meeting these criteria is sold pursuant to Subpart C, the pipeline may add to the basic rate an amount sufficient to offset the increase in its weighted average acquisition cost.

The reporting requirements proposed in § 284.148 include an initial report, to be filed within 60 days after commencing deliveries under a Subpart C sale and "subsequent reports" whenever a significant change occurs in the information submitted with the initial report. If an extension of the sale is sought, an extension report must be filed not less than 90 days prior to the expiration of the sale. The extension report would consist of a current statement of the information required in the initial report and the terms of the proposed extension. Finally, within 60 days after termination of any sale or extension, a final report would be required of the purchases stating quantities purchased, amount paid and delivery points. All reports would be required to be under oath, signed by a senior official of the company.

As announced in the November 13 proposal, the Commission proposes to make rules implementing section 311(b) effective on March 1, 1979. For this reason, the period for the filing of comments on these proposed rules will end on February 21. In addition, a public hearing will be held. The Commission intends to take final action on the proposed regulations prior to March 1.

III. Written Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to 4:30 p.m., E.S.T., February 21, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions

will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NE., Washington, D.C., during regular business hours. Comments should by submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM79-*20*.

IV. Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on February 20, 1979, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on February 15, 1979.

Request to participate in the hearing should include a reference to Docket No. RM79-*20*, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m. on February 16, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95-621)

In consideration of the foregoing, the Commission proposes to amend Subchapter I, Part 284, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the direction of the Commission.

Kenneth F. Plumb,
Secretary.

1. Part 284 is amended in the table of sections by adding a new Subpart C in the appropriate numerical order new sections and titles to read as follows:

Subpart C—Certain Sales by Intrastate Pipelines

Sec.
284.141 Applicability.
284.142 Sales by intrastate pipelines.
284.143 Definition.
284.144 Rates and charge.
284.145 Terms and conditions.
284.146 Extensions.
284.147 Terminations.
284.148 Reporting requirements.

Authority: Natural Gas Policy Act of 1978, Pub. L. 95-621.

2. Part 284 is amended by adding a new Subpart C to read as follows:

Subpart C—Certain Sales by Intrastate Pipelines

§284.141 Applicability.

This subpart implements section 311(b) of the NGPA and applies to certain sales of natural gas by intrastate pipelines to:

(a) Interstate pipelines; and

(b) Local distribution companies served by interstate pipelines.

§284.142 Sales by intrastate pipelines.

Any intrastate pipeline may, without prior Commission approval, sell natural gas to any interstate pipeline or any local distribution company served by an interstate piepine, in accordance with the provisions of this subpart.

§ 284.143 Definition.

"Weighted average acquisition cost of natural gas" means the cost of natural gas to an intrastate pipeline for any calendar month in which deliveries pursuant to this subpart occur, computed by:

(a) Determining the actual quantities of natural gas (expressed in terms of MMbtu's) purchased by the intrastate pipeline from each source of supply, excluding any quantities for which the instrastate pipeline makes an adjustment under § 284.144(b), during a 12-month period ending no more than 90 days prior to the first day of any calendar month in which deliveries pursuant to the sale occur;

(b) Multiplying the MMbtu's attributable to each source of supply by the most recent price per MMbtu actually paid with respect to each source of supply; and

(c) Dividing the sum of the products computed under paragraph (b) of this section by the sum of the MMbtu's determined under paragraph (a) of this section.

§ 284.144 Rates and charges.

(a) *Basic rate.* The rates and charges by an intrastate pipeline pursuant to this subpart may not exceed:

(1) Its weighted average acquisition cost of natural gas; plus

(2) An amount to recover the costs of gathering, treating, processing, transporting, and delivering the natural gas as determined in accordance with § 284.123; plus

(3) An adjustment as determined under paragraph (b) of this section.

(b) *Adjustment.* With respect to natural gas sold pursuant to this subpart which:

(1) Is acquired under an existing contract;

(2) Is in excess of quantities which the intrastate pipeline would otherwise have acquired; and

(3) The price of which exceeds the intrastate pipeline's weighted average acquisition cost of natural gas, the intrastate pipeline may add to the basic rate under paragraph (a) of this section an amount sufficient to offset the increase in its weighted average acquisition cost of natural gas.

§ 284.145 Terms and conditions.

(a) No sale pursuant to this subpart or extension thereof may be for a period exceeding two years.

(b) Any sale pursuant to this subpart shall be subject to interruption to the extent that natural gas subject to the sale is required by the intrastate pipeline to provide adequate service to the pipeline's customers at the time of the sale.

(c) No sale pursuant to this subpart may involve natural gas acquired by the intrastate pipeline solely or primarily for the purpose of resale pursuant to this subpart.

(d) The Commission may by rule or order impose other terms and conditions as it deems appropriate and in the public interest.

(e) The Commission presumes that the cost of gathering, treating, processing, transporting, and delivery recovered under § 284.144 will be considered by the state regulatory authority in arriving at sales and transportation rates to enable the intrastate pipeline company to recover such costs and earn its allowed rate of return.

§ 284.146 Extensions.

(a) An intrastate pipeline seeking to extend a sale pursuant to this subpart shall file an extension report as provided by § 284.148(c).

(b) If an extension report as required in § 284.148(c) is duly filed, the proposed extension may take effect unless the Commission, prior to the beginning of the proposed extension, after opportunity for the oral presentation of data, views and arguments and for written comments, determines by order that the proposed extension is not approved. If the Commission determines, by order, that the proposed extension shall be modified, the extension may take effect only as modified.

§ 284.147 Terminations.

(a) Upon complaint of any interested person or upon the Commission's own motion, the Commission may by order terminate a sale pursuant to this subpart.

(b) Prior to issuing an order under paragraph (a) of this section, the Commission shall afford an opportunity

for the oral presentation of data, views and arguments, and for written comments.

(c) A sale under this subpart may be terminated if the Commission determines that:

(1) The termination is required to enable the intrastate pipeline to provide adequate service to its customers at the time of the sale;

(2) The sale involves natural gas acquired by the intrastate pipeline solely or primarily for the purpose of resale pursuant to this subpart;

(3) The sale violates any provision of this subpart or any term or condition established by rule or order of the Commission applicable to the sale; or

(4) The sale circumvents or violates any provision of the NGPA.

(d) Upon complaint of any interested person or upon its own motion, the Commission may, prior to a hearing as provided in paragraph (b) of this section, suspend a sale pursuant to this subpart pending the hearing if it determines that any of the findings under paragraph (c) of this section is likely to be made following the hearing.

§ 284.148 Reporting requirements.

(a) *Initial report.* Within 60 days after commencing deliveries under a sale pursuant to this subpart, an intrastate pipeline shall file with the appropriate state regulatory agency and with the Commission an initial report, under oath, signed by a senior official of the company, containing the following information:

(1) The exact legal name of the intrastate pipeline and the name, title and mailing address of the person or persons to whom communications regarding the sale pursuant to this subpart should be addressed;

(2) A description of the sale, including:

(i) The identity of the parties;

(ii) The dates of commencement and anticipated termination of the sale;

(iii) The estimated total and daily quantities (in MMbtu's) of natural gas; and

(iv) The rate to be charged;

(3) A computation showing the methodology for determining the weighted average acquisition cost of natural gas under this subpart;

(4) A computation showing the methodology to be employed for arriving at the rate charged to recover the cost of gathering, treating, processing, transporting and delivering the natural gas associated with the sale;

(5) Computation of an adjustment, if any, under § 284.165(b), including:

(i) The basis for attributing certain additional acquisitions of natural gas to a sale pursuant to this subpart;

(ii) The identity of the existing contract under which the additional acquisitions are made and the price (per MMbtu) of natural gas purchased under the contract; and

(iii) Each point of delivery of additional acquisitions of natural gas to the intrastate pipeline; and

(6) An affidavit that service pursuant to the sale is subject to interruption to the extent that natural gas subject to the sale under this subpart is required to enable the intrastate pipeline involved to provide adequate service to its customers at the time of the sale.

(b) *Subsequent report.* If any significant change occurs with respect to the information filed under paragraph (a) of this section, the intrastate pipeline shall file with the Commission and the appropriate state regulatory agency, under oath, appropriate amendments to its initial report, signed by a senior official of the company.

(c) *Extension report.* Not less than 90 days prior to the expiration of a contract for the sale of natural gas pursuant to this subpart, an intrastate pipeline seeking to extend the sale beyond the initial two-year period or any period of extension shall file with the Commission and the appropriate state regulatory agency an extension report signed by a senior official of the company, under oath, stating:

(1) Current information with respect to any matters required to be reported under paragraph (a) of this section; and

(2) The proposed terms of the extension.

(d) *Final report.* Within 60 days after the termination of any sale or extension under this subpart, the interstate pipeline or local distribution company served by an interstate pipeline which purchased natural gas pur-

suant to this subpart shall file with the Commission and the appropriate state regulatory agency, under oath, a final report signed by a senior official of the company, stating:

(1) The actual quantities of natural gas purchased, on a monthly and total basis;

(2) The actual rate paid (per MMbtu for each month and the total amount paid; and

(13) The points of delivery.

¶ 32,008 Interim Regulations Implementing the Natural Gas Policy Act of 1978 and Regulations Under the Natural Gas Act

44 F. R. 10336 (February 16, 1979).

[Docket No. RM79-22]

INTERIM REGULATIONS IMPLEMENTING THE NATURAL GAS POLICY ACT OF 1978 AND REGULATIONS UNDER THE NATURAL GAS ACT

Amendment and Clarification

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking and Public Hearing.

SUMMARY: The Commission proposes amendments relating to the effect of the Natural Gas Policy Act of 1978 on indefinite price escalator clauses in existing interstate and intrastate contracts for the first sale of natural gas.

DATES: Written comments due February 27, 1979. Public hearing to be held February 27, 1979.

ADDRESS: Send comments to:

Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.W., Washington, D.C. 20426 [Reference Docket No. RM79-22].

FOR FURTHER INFORMATION CONTACT:

James L. Lewis, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol Street, N.W., Washington, D.C. 20426, (202) 275-5842.

SUPPLEMENTARY INFORMATION:

NOTICE OF PROPOSED RULEMAKING AND PUBLIC HEARING

Issued: February 13, 1979.

I. INTRODUCTION

The Federal Energy Regulatory Commission (Commission) hereby gives notice of a proposal to amend Title 18, Code of Federal Regulations, Parts 154, 270 and 273, relating to the effect of the Natural Gas Policy Act of 1978 (NGPA),[1] on indefinite price escalator clauses in existing interstate and intrastate contracts for the first sale of natural gas. The Commission also gives notice that it will hold a public hearing with respect to this proposal. The Commission has previously requested comments on this issue, and on January 19, 1979 heard oral argument solely on these issues. The purpose of this notice is to set forth for a public comment a specific proposal for the treatment of escalator clauses in existing contracts as well as certain alternative approaches.

II. BACKGROUND

The Natural Gas Policy Act of 1978 prescribes ceiling prices for first sales of natural gas. However, both the statute and its legislative history make clear that the prices specified in the NGPA are ceiling prices only, and that contractual rights to purchase natural gas at a price below the ceiling are unaffected. Section 101(b)(9) of the NGPA provides:

> [in] the case of any price which is established under any contract for the first sale of natural gas and which does not exceed the applicable maximum lawful price under this title . . ., such maximum lawful price . . . shall not supersede or nullify the effectiveness of the price established under such contract.

The Statement of Managers explains:

> All maximum lawful prices are ceiling prices only. In no case may a seller receive more than his contract permits. (H.R. Report No. 95-1752, 95th Cong., 2nd Sess., p. 74.)

The vast majority of contracts for the sale of natural gas contain "escalator" clauses of one kind or another, which permit upward price adjustments during the term of the contract. While section 101(b)(9) and the accompanying legislative history preserve private contractual rights to purchase gas at a price lower than the statutory ceiling prices, the application of section 101(b)(9) to indefinite price escalation clauses involves difficult questions of construction of the statute, the Commission's regulations, and pri-

[1] Pub. L. 95-621, 92 Stat. 3350.

vate contracts. In particular, do these clauses authorize the seller to collect, and bind the purchaser to pay, the ceiling prices under the NGPA? If these clauses do not authorize collection of the NGPA rates, to what extent may parties modify their contracts to collect NGPA ceiling prices?

Among the provisions published by the Federal Energy Regulatory Commission (Commission) in its Interim Regulations Implementing the NGPA [2] was § 270.205 (18 CFR § 270.205), entitled *Indefinite price escalator clauses*, Which provided:

(a) The establishment of maximum lawful prices under the NGPA shall not trigger indefinite price escalator clauses in existing intrastate or interstate contracts.

(b) For purposes of this section, the term 'indefinite price escalator clause' shall have the same meaning as provided in section 105(b)(3)(B) of the NGPA.[3]

As the Commission stated in the preamble to the Interim Regulations, § 270.205 incorporated the expression of Congressional intent at page 83 of the Statement of Managers respecting the effect of the establishment of maximum lawful prices on indefinite price escalator clauses in existing intrastate contracts. The Commission applied the same rule to interstate contracts.[4]

Since the adoption of the interim regulations, the Commission has received numerous comments respecting § 270.205 and requests for its clarification, amendment, or repeal.[5] After consideration of all views expressed, including those contained in comments received before February 1, 1978, we propose to amend and clarify § 270.205. Amendments to other provisions of our regulations are also proposed in order to reflect and implement the action we are proposing today concerning the price escalation provisions.[6]

In the discussion which follows, we shall summarize the Commission's proposal, and set forth the reasons for its conclusions as applied to contracts for natural gas dedicated to interstate commerce and existing intrastate contracts.

III. SUMMARY OF PROPOSED COMMISSION POLICY WITH RESPECT TO INDEFINITE PRICE ESCALATOR CLAUSES

The Commission proposes the following policy, interpretation of existing regulations, and modifications of

[2] Interim Regulations Implementing the Natural Gas Policy Act of 1978 (Interim Regulations), issued in Docket No. RM79-3, December 1, 1978, 43 FR 56463 (December 1, 1978).

[3] Section 105(b)(3)(B) of the NGPA defines indefinite price escalator clause as follows:

(B) Definition of Indefinite Price Escalator Clause.—For purpose of this paragraph, the term 'indefinite price escalator clause' includes any provision of any contract—

(i) which provides for the establishment or adjustment of the price for natural gas delivered under such contract by reference to other prices for natural gas, for crude oil, or for refined petroleum products; or

(ii) which allows for the establishment or adjustment of the price of natural gas delivered under such contract by negotiation between the parties.

[4] See discussion at page 26 of the Interim Regulations.

[5] The Commission has received public comment and inquiry at the various NGPA implementation seminars, through its telephone hot line program, and at public hearings held before staff panels in Washington, New Orleans, San Francisco and New York. In response to these comments, we convened an oral argument on the issues this order addresses before the Commission *en banc* on January 19, 1979. Nineteen parties participated in this argument, and numerous written comments were received. (*See* Notice of Seminars Concerning Implementation of the Natural Gas Policy Act of 1978, November 14, 1978; *see also*, FERC News Release FE-474, November 13, 1978. FERC News Release FE-468, November 1, 1978, and *Order Setting Oral Argument*, issued January 12, 1979, in Docket No. RM79-3, in which the Commission asked participants to respond to nine questions concerning the effect of the NGPA on indefinite price escalation provisions in both interstate and intrastate contracts.)

[6] This proposal is issued in a docket number other than that which applies to our other interim NGPA regulations. As noted below, we asked for comments on the applicability of indefinite price escalator clauses separately from other aspects of our interim rules. Severance of the dockets, we believe, enables the Commission and the public to focus more clearly on the discrete issues addressed by these proposed regulations. However, we do take official notice of and incorporate by reference herein, those portions of the records in Dockets Nos. RM79-3 and RM79-4, which contain comments on those issues which are affected by this proposal.

its existing regulations with respect to indefinite price escalator clauses:

A. *Escalator Clauses in Interstate Contracts.*

1. *The Area Rate Clause.*

In the case of contracts for the sale of natural gas which was committed or dedicated to interstate commerce on November 8, 1978, and to which the Natural Gas Act (NGA) remains applicable, § 154.93 of the Commission's regulations permits interstate natural gas contracts to contain provisions, known as "area rate clauses", which "permit a change in price to the applicable just and reasonable area ceiling rate which has been, or which may be, prescribed by the Commission for the quality of the gas involved." [7] The Commission does not believe it to be a correct interpretation of such a clause, or the Commission's regulation which makes such clauses permissible, to conclude that the purchaser by agreeing to such clause thereby bound himself to pay the *maximum* lawful prices prescribed by the NGPA. The Commission's proposal provides, that parties may mutually agree to modify their contracts to permit collection of NGPA ceiling prices. An amendment to the contract or separate letter agreement must be entered into in order to provide the contractual authority to charge and collect the NGPA rates. (See Part C below.)

2. *Variant Clauses.*

The Commission's regulations under the Natural Gas Act make inoperative escalation clauses which differ from those specified in § 154.93. The Commission has accepted for filing contracts which contain "variant" escalator clauses which are broader in scope than the clauses described in § 154.93. Some of these clauses by their terms would permit collection of the NGPA rates. But in accepting these clauses, the Commission has generally made clear in its regulations and conditions to its certificates that such clauses have no effect under the NGA.

If a contract for the sale of natural gas which was committed or dedicated on November 8, 1978, and to which the NGA remains applicable contains such clauses and was accepted for filing, that clause will be given no greater effect than a clause permitted under 18 CFR § 154.93(b-1), unless the producer can show that the Commission has either specifically approved the variant clause or has specifically waived the provisions of § 154.93 which would make the broader application of the clause inoperative.

B. *Escalator Clauses in Existing Intrastate Contracts.*

1. *Where Section 105(b)(1) is Applicable.*

If section 105(b)(1) of the NGPA [8] is the highest applicable maximum lawful price applicable to a first sale of natural gas, then escalator clauses may increase the contract price in accordance with the contract terms (as those terms were in effect on November 9, 1978) but not to a level in excess of the new natural gas price prescribed under section 102 of the NGPA. The Commission intends to leave the interpretation of these clauses initially to the parties; however, a seller could subject himself to enforcement action by the Commission for violation of the NGPA, if an interpretation of an escalator clause is inconsistent with the terms of the clause.

2. *Where Section 105(b)(1) is Inapplicable.*

If section 105(b)(1) does not apply to an existing intrastate contract or if a higher maximum lawful price is applicable under another provision of the NGPA, then the Commission intends that the interpretation of any intrastate contract and any escalator clause contained in such contract be left to the parties and to state law. However, the applicable maximum lawful price as prescribed by the applicable section of the NGPA may not be charged and collected without contractual authority and, of course, may not be exceeded.

C. *Contract Modification.*

1. *Interstate Contracts.*

In the case of contracts for the sale of natural gas which was committed or dedicated on November 8, 1978, and to which the NGA remains applicable, the parties to the contract are free to modify their contracts to permit collection of any price so long as that price does not exceed the NGPA ceiling prices applicable to the subject natural gas. Neither the NGPA nor the *Mobil-Sierra* doctrine [9] preclude bi-

[7] 18 CFR 154.93.

[8] Section 105(b)(1) applies to existing intrastate contracts where the contract price on November 9, 1978, was less than $2.06 per MMBtu.

[9] *United Gas Pipeline Company* v. *Mobil Gas Service Corporation*, 350 U.S. 332 (1955), and *FPC* v. *Sierra Pacific Power Co.*, 350 U.S. 348 (1955).

lateral contract modification to permit collection of NGPA ceiling prices or interim or retroactive collections of such prices. Bilateral contractual modification must be evidenced by a contract amendment or separate letter agreement.

Passthrough of increased purchased gas costs which result from a modification, in an arms length transaction, of a contract in order to permit collection of an NGPA rate will not be precluded under section 601(c)(2) of the NGPA unless fraud, abuse or similar grounds are found. Modifications of contracts which contain area rate or other escalator clauses in order to collect NGPA prices will not be challenged on the basis that such a modification is an abuse of the pipeline's responsibilities to its customers.

A contract modification may in certain circumstances be retroactive to December 1, 1978, may be the basis for collection of a rate under the Commission's blanket affidavit procedure under 18 CFR § 154.94(h), and may authorize collection of interim and retroactive collections under Part 273 of the Commission's interim regulations.

2. *Intrastate Contracts.*

In the case of natural gas which is not committed or dedicated under the NGPA, the parties may effect bilateral modifications of existing contracts, so long as the new contract price does not exceed the applicable maximum lawful price. Of course, where section 105(b)(1) is the applicable maximum lawful price and no higher price is applicable under another section, the ceiling price cannot exceed the price according to the terms of the contract as they were in effect on November 9, 1978, and no price increase can be effected through contract modification.

IV. INTERSTATE SALES TRANSACTIONS

A. *Requirement for Contractual Authorization in Interstate Transactions.*

Both the Natural Gas Act and the NGPA recognize the necessity of contractual authorization to charge and collect a price for the sale of natural gas. As noted above, the NGPA prescribes *ceiling* prices for first sales of natural gas, while preserving contractual rights of buyers to purchase gas at a price below the ceiling. As Congressman John D. Dingell stated, on behalf of the floor managers of the NGPA:

> The rule set forth in section 101(b)(9) is that the legislation establishes ceiling prices. Contract prices may be lower than the federal maximum lawful price. In such cases the contractual arrangement between the parties continues to govern their relationship, and is not superseded by the federal ceiling price.[10]

Similarly, the *Mobile-Sierra* doctrine under the Natural Gas Act holds that a utility may not unilaterally file a section 4 rate increase unless such increase is consistent with the terms of the applicable sales contract.[11] That is, rate changes which are authorized by contractual provisions are permissible; those which are inconsistent are not.[12]

The first question the Commission must address with respect to existing contracts for first sales of natural gas to which the Natural Gas Act remains applicable is whether the escalator clauses in these contracts are effective to provide contractual authorization to collect the NGPA prices. In answering this question, the Commission must interpret its own regulations and address the Congressional intent embodied in the provisions of the NGPA, and to the extent relevant, the presumed intent of the parties who have contractually bound themselves to pay the ceiling prices.

B. *The Area Rate Clause.*

The Commission's regulations make inoperative any provision in an interstate contract which provides for a change in price which is not in the

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[10] 95 *Cong. Rec.* 13117 (daily ed. October 14, 1978).

[11] See, note 9, *supra* at 9.

[12] *Richmond Power & Light* v. *FPC*, 481 F.2d 490 (1973). See *Otter Tail Power* v. *FPC*, 536 F.2d 240 (1976); *Appalachian Power Co.* v. *FPC*, 529 F.2d 342 (1976).

form described in the regulations.[13] One of the four permissible types of clauses, and the principal clause in question here, is the "area rate clause." This clause permits a change in price "to the applicable just and reasonable area ceiling rate which has been, or which may be, prescribed by the Commission for the quality of gas involved * * *."

Congress, in enacting the NGPA, was aware of this provision of the Commission's regulations, and specifically preserved its applicability. The Statement of Managers explains:

> This section of the conference agreement [relating to indefinite price escalator clauses] is not intended to apply to interstate contracts in existence as of the date of enactment. Such contracts are currently subject to regulation by the Commission pursuant to the Natural Gas Act. Commission regulations bar the use of indefinite price escalator clauses in interstate sales.[14]

Senator Henry M. Jackson, Senate floor manager of the NGPA, stated, in referring to indefinite pricing provisions, "However, operation of those clauses is prohibited by current Commission regulations. *There is no intent to change or otherwise modify that prohibition.*"[15]

The area rate clause by its terms permits price increases only to the "applicable just and reasonable area rate . . . prescribed by the Commission." The NGPA rates are not rates described in this clause. They are area rates prescribed by the Commission using the cost-based methodology developed in the area rate cases under the Natural Gas Act.[16] Moreover, they are not rates prescribed by the Commission. Rather, they are prescribed by Congress. The Commission has not prescribed, and under the Natural Gas Act probably could not prescribe, the NGPA rates.

The examination of the development of the area rate clause (which appears in Part C below)[17] provides no more basis for concluding that the clause authorizes collection of the NGPA rates than does examination of the text. The Commission, both at the time of promulgation of the area rate clause in 1966, and in its application of the clause thereafter, has consistently refused to permit its use to collect rates other than the cost-based area (and later national) rates. No other rates, even just and reasonable special relief rates, have ever been authorized to be collected under the clause.

The text of the area rate clause does not require purchasers to pay the legislatively established NGPA rates. The history of the development and appli-

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[13] "§ 154.93 Rate schedule defined.

For the purpose of §§ 154.92 through 154.101 'rate schedule' shall mean the basic contract and all supplements or agreements amendatory thereof, effective and applicable on and after June 7, 1954, showing the service to be provided and the rates and charges, terms, conditions, classifications, practices, rules and regulations affecting or relating to such rates or charges, applicable to the transportation of natural gas in interstate commerce or the sale of natural gas in interstate commerce for resale subject to the jurisdiction of the Commission: *Provided*, That in contracts executed on or after April 3, 1961, for the sale or transportation of natural gas subject to the jurisdiction of the Commission, any provision for a change of price other than the following provisions shall be inoperative and of no effect at law; the permissible provisions for a change in price are:

(a) Provisions that change a price in order to reimburse the seller for all or any part of the changes in production, severance, or gathering taxes levied upon the seller;

(b) Provisions that change a price to a specific amount at a definite date;

(b-1) Provisions that permit a change in price to the applicable just and reasonable area ceiling rate which has been, or which may be, prescribed by the Commission for the quality of the gas involved; and

(c) Provisions that, once in five-year contract periods during which there is no provision for a change in price to a specific amount (paragraph (b) of this section), change a price at a definite date by a price-redetermination based upon and not higher than a producer rate or producer rates which are subject to the jurisdiction of the Commission, are not in issue in suspension or certificate proceedings, and, are in the area of the price in question: *Provided further*, That any contract executed on or after April 2, 1962, containing price-changing provisions other than the permissible provisions set forth in the proviso next above shall be rejected. [Order 242, 27 FR 1357, Feb. 14, 1962, as amended by Order 329, 31 FR 15486, Dec. 8, 1966]"

[14] Statement of Managers at 83.

[15] 95 *Cong. Rec.* § 15021 (daily ed. September 13, 1978).

[16] *Area Rate Proceeding, et al.* (Permian decision), 34 FPC 159 (1965); remanded, *Skelly Oil, et al.* v. *FPC*, 375 F.2d 6 (10th Cir. 1967), aff'd, 390 U.S. 747 (1968).

[17] See discussion, pp. 19-27, *infra*.

cation of the area rate clause demonstrates that the FPC intended to limit the application of these clauses to national or area rates prescribed by the Commission. Nevertheless, a number of parties have asked the Commission to disregard the plain text of its regulations and the consistent interpretation of them, and hold that the area rate clause requires a purchaser, over his objections, to pay the NGPA rates. The Commission concludes that the Congressional intent embodied in the NGPA requires that the Commission interpret its regulations according to their plain meaning.

First, section 101(b)(9) of the NGPA, the Statement of Managers, and the managers' floor statements all make unmistakably clear that the NGPA does not require any purchaser to pay the ceiling prices established by the statute. The establishment of these ceiling prices is intended to constrain prices charged by sellers and not to force up prices paid by buyers.

Second, the NGPA is intended to provide a transition from a bimodal, partially regulated gas market to a single national market where prices will be largely determined by negotiation between buyer and seller. The statute's relatively high, and rapidly escalating, ceiling prices serve the function of imposing an upper limit on negotiated prices, leaving the market free to operate within the ceiling prices. An interpretation of the area rate clause which would require an unwilling buyer to pay the NGPA rates would not permit operation of the market within the ceiling prices.[18]

C. *Development of the Area Rate Clause.*

In 1961, the Federal Power Commission issued Order No. 232 [19] which held that certain contractual clauses providing for adjustments in the price of natural gas, which it termed "indefinite price escalation clauses," were contrary to public policy and were, accordingly, void.[20]

In an order issued the same day, *The Pure Oil Company*,[21] the Commission amplified on its rationale for making these clauses inoperative. In referring to a particular type of indefinite escalator provision, the three-party favored nation clause, the Commission stated that these clauses were offensive because:

> There need be no economic or other substantial justification for the increase . . . In our view, such an artificial ground for a propsoed increase, operating in such a mechanical and arbitrary manner, and lacking any substantial relationship to the factors which bear on the value of gas or on a determination of a reasonable level of rates for it, does not constitute a proper basis for filing proposed increased rates or a sufficient justification for our giving effect to such a filing.[22]

In Order No. 232-A,[23] issued four weeks later, the FPC amended § 154.93 of its regulations so as to eliminate the distinction between definite and indefinite escaltors. Rather than bar indefinite escalators, the amended rule

[18] The anomaly of such a result as well as a measure of the impact of such a result can be seen in the example of flowing gas from a well commenced before 1973. The November 1978 rate under Opinion 770-A is, in most cases, No. 29. If such a well qualifies as a stripper well under section 108, the December 1978 price is $2.224, a 666 percent increase. The estimated ceiling price in mid-1985 (using a 6 percent inflation rate) is $4.15, over a 1000 percent increase. *See* Economic Analysis of H.R. 5289, Natural Gas Policy Act of 1978, prepared by the Staff of the Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, House of Representatives, dated October 13, 1978.

[19] 25 FPC 379 (1961).

[20] 25 FPC 379, 380 (1961). The Commission defined the therms "definite escalation clause," and "indefinite escalation clause," and provided that the former were permissible, while the latter should be prescribed. It defined a definite escalation clause as:

> . . . any provision in an independent producer's contract for the sale of natural gas . . . which sets forth the price to be paid for natural gas delivered thereunder in terms of a specific price per unit including, in addition to the initial price, any increases therein by specific amounts at definite future dates, or in any provision which changes the specific price in order to reimburse the seller for all or any part of the changes in production, severence, or gathering taxes levied upon the seller. [footnote omitted]

Indefinite escalation clauses were defined as "any provision other than a definite escalation clause . . . under which the price in a contract for the sale or transportation of natural gas by an independent producer . . .

[21] 25 FPC 383 (1961).

[22] *Id.* at 389.

[23] 25 FPC 609 (1961).

enumerated particular types of escalator provisions which would be permissible. The permissible clauses included those types of provisions which had earlier been defined as definite escalation provisions, as well as provisions that would permit price redetermination once every five years to "in-line" rates—that is, to rates:

> . . . based upon *and not higher than* a producer rate or porducer rates which are subject to the jurisdiction of the Commission, are not in issue in suspension or certificate proceedings, and, are in the area of the price in question. (Emphasis added).

The next FPC pronouncement concerning price escalator provisions came with Order No. 242, issued in 1962.[25] The Commission's views concerning the desirability of permitting the operation of indefinite escalator provisions had not changed. Neither had its rationale. The FPC referred to these provisions as "incompatible with a scheme of effective rate regulation,"[26] and stated:

> We held in the *Pure Oil* case that indefinite escalation clauses are contrary to the public interest and restated this conclusion in Order No. 232-A. Increases in producer prices, triggered by indefinite escalation clauses, have resulted in a flood of almost simultaneous filings. *These filings bear no apparent relationship to the economic requirements of the producers who file them. The Natural Gas Act contemplates that prices, to be just and reasonable, be related to economic needs.* (*Emphasis added*).[27]

The FPC shifted its approach toward escalation provisions in Order No. 242. Previously, such clauses were merely held inoperative. Order No. 242 provided that such clauses would, in addition to being inoperative, also be grounds for rejection of the contract in which they were included. Section 154.93 was amended accordingly.

The Orders discussed above involved types of escalation provisions which antedated the FPC's area rate policy. Order No. 329, issued in 1956,[28] however, dealt directly with the so-called "area rate clause". In the notice of proposed rulemaking which preceded Order No. 329,[29] the Commission had proposed an addition to the permissible types of escalation provisions. The Commission stated:

> Another type of contractual provision which has come into use provided in effect, for an additional price increase up to the just and reasonable rate which may be prescribed in an area rate proceeding. It appears that such a price provision for a change to an, as yet, undetermined area rate should be permitted and that a general rule should be issued to advise buyers and sellers that such provisions are permissible.[30]

Comments filed in response to this notice by Phillips Petroleum Company and the FPC's response thereto provide considerable insight into the FPC's purpose. Phillips' comments argued that the proposed amendment was restrictive in limiting the permissible provisions to permit an increase only to the just and reasonable *area* rate. Phillips stated:

> The proposed amendment would limit such contract provisions to permit rate increases to just and reasonable rates determined in area rate proceedings. This restriction seems to indicate that just and reasonable rates may be determined only in area rate proceedings.[31]

Phillips argued that, in view of the provisions for special relief contained in the FPC's area rate opinions, the proposed rule should be expanded to permit an increase to any special relief rate, as well as an area rate. The textual amendment proposed by Phillips, however, was much broader in scope than its argument might suggest. Phillips proposed an amendment to the rule which would have permitted contractual provisions which "permit a change to the just and reasonable rate prescribed, or which may be prescribed, for the sale of gas in question."[32] Phillips' position was that a

[25] 25 FPC at 610. Order 232-A was upheld in *Pan American Corporation* v. *Federal Power Commission*, 352 F.2d 241, 244 (10th Cir. 1965).

[26] 27 FPC 339 (1962). Order No. 242 was reversed by the Tenth Circuit, 317 F. 2d 796 (10th Cir. 1963). The Supreme Court, however, upheld the FPC in *Federal Power Commission* v. *Texaco, Inc.*, 377 U.S. 33 (1964).

[27] *Id.* at 340.

[28] *Id.*

[29] 36 FPC 925 (1966).

[30] 31 FR 1316 (1966).

[31] *Id.*

[32] Phillips' Comments filed in P.P.C. Docket No. R-298, at 5.

[33] *Id.* at 5, 6.

clause which allowed an increase to any just and reasonable rate, whether or not the rate was determined in an area rate proceeding, should be permitted.

The Commission explicitly relected this argument, and adopted the rule without Phillips' proposed amendment. In doing so, it stated, "we see no need to further liberalize the pricing provisions permitted in proposed contracts beyond the scope of the proposed rule." [33] The Commission's action in limiting the scope of permissible clauses to just and reasonable area rates prescribed by the Commission was consistent both with its prior policies, and its future practice.[34]

In 1974, the FPC moved from the area rate method of regulating producers' prices to a nationwide rate scheme. The rate-setting methodology employed in Opinion Nos. 699 and 770 was, however, an average cost methodology as was used in the various area rate opinions. While the Commission did not, in either of the national rate opinions, explicitly hold that the setting of the national rates triggered area rate clauses, it did so hold implicitly, by accepting rate increase filings based on area rate clauses up to the Opinion Nos. 699 and 770 ceilings. This action cannot be interpreted as a change in the Commission's view toward the scope of area rate clauses, however. The methodology adopted in Opinion No. 699 was similar to the cost-based method of setting area rates. Accordingly, the Commission's action in permitting the national rates to trigger area rate clauses was consistent with its past expressions of policy. That is, area rate clauses were permitted in Order No. 329 because the resulting rates were arrived at using the same cost-based ratemaking methodology as was used in the area rates. Indeed, the national rate and its cost-based methodology were specifically designed to replace the area rates. For the same reason, the FPC's actions in Opinion Nos. 742 and 742-A, in which it held that an area rate clause provided contractual authorization for collection of the small producer ceiling rate,[35] was in line with prior FPC practice.

In summation then, the review of FPC practice and precedent reveals that the Commission first outlawed all indefinite escalator clauses. The broad initial prohibition was progressively relaxed, first to permit price redeterminations every five years to collect "in-line prices," second, to permit collection of area rates which the Commission prescribed using the cost-based *Permian* methodology, and, third, to permit collection of natural rates which were substituted for the area rates, but which used essentially the same methodology. The Commission has never regarded the area rate clause as constituting contractual authorization to charge a just and reasonable rate not established in an area or national rate proceedings.

D. *Other Arguments Presented to the Commission.*

In addition to the other arguments stated above, the Commission takes note of the fact that the New York Public Service Commission has suggested in its written comments in the previous proceedings on this issue that interpretation of area rate clauses [36] and other contractual provisions turns on "the specific language of the contract rather than any inchoate inten-

[33] 36 FPC 925, 926 (1966).

[34] See discussion, *supra*. The Commission has always required an explicit contractual amendment authorizing collection before it permits a special relief rate to go into effect. This practice evidences the Commission's view that an area rate clause did not permit escalation to *any* just and reasonable rate whatever. Upon adopting the area rate method of producer ratemaking, the Commission again changed its procedural approach to impermissible clauses. It had formerly rejected these clauses, as provided in Order No. 242. Thereafter, the FPC began granting waivers of § 154.93 for filing purposes only and conditioning certificates so as to render clauses not permitted by the rule inoperative.

[35] *See* Opinion No. 742, issued August 28, 1975 in Docket No. R-393, mimeo p. 10; Opinion No. 742-A, issued July 27, 1976 in Docket No. R-393, mimeo p. 12. The small producer rates were formulated after the Commission found that exploration and development costs for small were higher than those for large producers. See, Opinion No. 742 at mimeo pp. 3-6; and Opinion No. 742-A at mimeo pp. 5-8.

[36] For purposes of this discussion, it is assumed that the clause being interpreted is permissible under 18 CFR 154.93. See discussion, *infra*, concerning variant clauses.

tion of the parties." [37] This standard of interpretation has also been suggested by UGI Corporation in its comments at page 3.[38] It has long been held that the plain meaning of the words must be applied in interpreting contracts.[39] Applying this rule would only further support the position that a permissible area rate clause does not by its own terms supply contractual authorization for collection of NGPA maximum lawful prices.[40]

An argument has also been made that the NGPA prices are "prescribed by the Commission" as required by § 154.93(b-1), and accordingly, area rate clauses are triggered by the mere act of quarterly publication of the inflation-adjusted NGPA rates.[41] Certain Indicated Producers state:

> [t]he methodology by which the Commission establishes rates has changed, with Congress providing a more exact statutory method under the NGPA than the previously established method under the Natural Gas Act by which such rates shall be set. However, section 101(b)(6) makes clear that it is incumbent upon the Commission to prescribe such rates.[42]

Section 101(b)(6) provides:

> The Commission shall—
> (a) not later than 5 days before the beginning of any month, *compute* and *make available* the maximum lawful prices *prescribed under this title* for such month and the monthly equivalent of the annual inflation adjustment factor such month, and
> (b) as soon as possible thereafter, publish such maximum lawful prices and such factor for such month in the Federal Register. (Emphasis added).

Thus, the argument goes, the act of computation and publication required by section 101(b)(6) is equivalent to prescribing a just and reasonable price within the meaning of an area rate clause.

This argument is without merit. The NGPA itself recognizes the distinction between "computing," "making available," and "publishing" on the one hand, and "prescribing" on the other. Section 101(b)(6) requires the FERC to "compute" and "publish" the maximum lawful prices "prescribed under this title." The statute clearly recognizes that the Congress had performed the function of prescribing maximum lawful prices. In addition, it must be noted that the Congress took care to use particular language when it desired to give this Commission the authority to prescribe rates. There are specific provisions which grant the Commission the authority to "prescribe" rates higher than the Congressionally mandated ceiling prices.[43]

E. *Variant Escalator Provisions in Interstate Contracts.*

As is noted above, and as is recognized in the legislative history of the NGPA, the Commission has for many years regulated the use of price escalator clauses in interstate contracts. While § 154.93 provides that contracts containing impermissible clauses will be rejected, the FPC adopted the practice of waiving § 154.93, and accepting such contracts for filing.[44] The waiver is only partial, however, in that it is

[37] Comments of the Public Service Commission of the State of New York on "Indefinite Price Escalator Clauses" at 2; filed in Docket No. RM79-3 on January 18, 1979 (hereinafter New York Comments).

[38] Citing *Chemical Constr. Corp.* v. *Continental En'gr, Ltd.*, 407 F.2d 989 (5th Cir. 1969).

[39] *See Fidelity and Casualty Company of New York* v. *Lott*, 273 F.2d 500, 502 (5th Cir. 1960), where the court stated, "[w]here the terms of a written contract are clear and unambiguous they alone are looked to ascertain their meaning." *See also, Henrietta Mills* v. *Commissioner of Internal Revenue*, 52 F. 2d 931, 934 (4th Cir. 1931).

[40] See, earlier discussion at pp. ——.

[41] See comments of Indicated Producers at 4.

[42] Id.

[43] NGPA sections 104(b)(2), 106(c), 107(b) and 109(b)(2). Indicated Producers state in their comments at page 5 that the Commission is "authorized" to compute and publish the NGPA prices. The statute, however, *requires* that we do so. The section 101(b)(6) direction to compute and publish the NGPA prices assigns to the Commission a function which is clearly ministerial and permits no exercise of discretion by the Commission. In no sense does the Commission prescribe the maximum lawful prices.

[44] "The Commission grants such waiver by including the following language in orders issuing certificates:

> Section 154.93 of the Regulations is hereby *waived to permit the filing of the contract which contains impermissible pricing provisions* [The prohibited sections of the contract are here frequently identified and their nature alluded to]. Applicant is advised that the granting of such waiver does not constitute approval of such provisions and *any rate increase based on such pricing provisions of Section 154.93 of the Commission's Regulations is subject to rejection.*

This policy was adopted so as to permit parties to file contracts without negotiating amendments to expunge the offending clause from their contracts.

granted "to permit the filing of the contract which contains impermissible pricing provisions" in order to avoid the necessity of rejecting the contracts and requiring refiling after expunging the offensive language. The Commission accomplished the same purpose by certificate condition. The waiver is conditioned to provide that no rate increase based on an impermissible provision will be permitted.

As we discussed above, the NGPA has not disturbed the Commission's regulation of escalation provisions in interstate contracts for so long as the NGA remains applicable to the sale. The Commission remains free to hold certain clauses impermissible, to grant waiver of and to interpret its regulations, and to condition certificates. Clauses which are impermissible under § 154.93, then, remain impermissible. The partial waivers which we have granted for filing purposes only, remain effective, and of course, the waiver remains partial.

Thus, a clause which has been accepted for filing, and which by its terms permits the collection of rates prescribed by legislation will not be effective for rate purposes, unless the Commission has specifically approved the clause for all purposes, or has granted a full waiver of § 154.93. We have held above that clauses which are permissible under § 154.93(b-1) do not supply contractual authorization for the collection of NGPA prices. *A fortiori*, then, those clauses which have been and still are impermissible do not operate to provide any additional contractual authority.

Nor do we believe that the NGPA triggers the variation of the area rate clause which refers to the "FPC or any successor governmental authority" and which New York has described as a typical clause.[45] It has been suggested that the Congress is a "successor governmental authority." We disagree. This Commission and the FPC are, in fact, creatures of the Congress, and fulfill only those functions which the Congress assigns to them. The term "successor" [46] generally denotes a demise of the original entity which is then replaced by another. The FPC, it is true, has been abolished. However, it was replaced by the FERC, not by Congress. Furthermore, as New York has stated,[47] the prevalence of provisions, such as deregulation clauses, which refer specifically to Congressional action, would suggest that any contract which does not make such an explicit reference cannot be viewed as evincing the party's intention to pay Congressionally-set prices.[48]

F. *Modification of Existing Interstate Contracts.*

Although existing area rate clauses do not provide authorization to collect NGPA prices, there is no impediment undet the NGPA to the parties' re-negotiating or amending their interstate contracts explicitly to provide for the collection of an applicable maximum lawful price. If the well or wells in question are otherwise eligible for a maximum lawful price, these modifica-

[45] See the Comments of the New York Public Service Commission filed in this docket, at page 3. The clause described as typical provides:

It is agreed that if the Federal Power Commission, *or any successor governmental authority* having jurisdiction in the premises covered by this agreement prescribes or approves a ceiling rate of general application to the area in which this sale is located by *hearing, rulemaking or Commission-approved settlement* in a proceeding instituted in accordance with Sections 4, 5, 6, 16 or any other section of the Natural Gas Act, or any successor statutory authority, which exceeds the price otherwise herein provided to be paid, then the price to be paid by Buyer to Seller hereunder shall be such higher rate effective as of the date such rate is prescribed or approved by the Commission. It is recognized that the provisions of this Section 8(a), Subsection (ii), may be activated at any time and from time to time as higher ceiling rates are determined in the manner set out herein, and it is the intent of the parties that any and all of such higher rates shall activate the provisions of this Section 8(a), Subsection (ii).

[46] *See, Black's Law Dictionary*, Revised Fourth Edition (1968) at p. 1600. "One that succeeds or follows; one who takes the place that another has left, and sustains the like part or character; one who takes the place of another by succession.

[47] New York Comments at 4.

[48] Section 154.93 does not permit the filing of contracts which contain variant clauses unless the Commission grants a waiver of § 154.93. (See discussion, *supra.*) Furthermore, it appears that in the particular clause quoted, reference to a successor authority was intended to refer to an administrative agency which set rates "by *hearing, rulemaking* or Commission-approved settlement." (Emphasis added.)

tions would operate as contractual authorization. The amendments should be filed with the Commission as supplements to the applicable producer rate schedule.

Because the Commission's position on escalator clauses will be enunciated after the effective date of the NGPA, we believe out of fairness to the parties to contracts containing these clauses that any contract modification made in response to this order may provide that the amendment is effective so as to permit the collection of NGPA prices retroactively to December 1, 1978.[49] Any contract authority for such retroactive collection must be embodied in the contract modification. Likewise, if a contract amendment permits interim collection of a maximum lawful price, then it will be permitted to so operate.

Another matter which the Commission must address is the question of to what extent a pipeline may pass on its increased costs which are attributable to such contract modifications. Section 602(c)(1) of the NGPA provides that the FERC may not deny an interstate pipeline recovery of purchased gas costs if the amount paid for the gas is deemed to be just and reasonable, except by reason of fraud, abuse or similar grounds. Maximum lawful prices are deemed to be just and reasonable. Passthrough of increased gas purchase costs resulting from contract modification to a price not in excess of the ceiling price is, therefore, permissible in the absence of fraud, abuse or similar grounds.

Questions have arisen as to whether passthrough of cost increases resulting from contractual modifications to collect the NGPA prices may be precluded on the basis of fraud, abuse or similar grounds. The question of what constitutes "fraud, abuse or similar grounds" is not one which the Commission is prepared to give a definitive answer to at this time. However, the Commission is prepared to conclude that if an interstate pipeline is a party to a contract containing an area rate or similar escalation clause, the parties may negotiate a contract modification to collect the NGPA prices. The Commission proposes not to preclude the passthrough of prices paid pursuant to such modifications negotiated in an arm-length transaction on the grounds that such modifications are an abuse of the pipeline's responsibilities to its customers.

These contract amendments may provide for collection of a specific maximum lawful price, or they may permit collection of the highest applicable maximum lawful price under the NGPA. To the extent that the amendment permits collection of the highest applicable price and to the extent that these prices are adjusted for inflation, such an amendment could be characterized as a price escalation provision. Section 154.93 governs escalation provisions in interstate contracts. Accordingly, we propose to amend § 154.93 to permit the filing and operation of contracts containing so-called "NGPA escalation clauses." [50]

We also propose to amend the rules adopted in Orders No. 15 and 15-A,[51] concerning blanket affidavit filings and protest procedure. Order No. 15 prescribed a blanket affidavit to be filed to permit collection of NGPA prices and adjustment. Order No. 15-A stated explicitly that such affidavits must be supported by contractual authorization, and prescribed a protest procedure in which any person could raise the issue of lack of the requisite contractual basis. The integrity of this procedure should be maintained. If after protest or upon Commission review it is determined that an affidavit is not supported by contractual authorization, the Commission may reject the affidavit. However, blanket affidavits encompassing more than one contract would only be rejected with respect to those prices which are charged or collected without the requisite contractual authorization.

We have received inquiries concerning the one cent per quarter escalation provision prescribed in Opinion No. 770-A. More particularly, if a seller does not have contractual authority to collect NGPA prices, may he collect the 770-A prices as adjusted each

[49] In *Southern Natural Gas Company* v. *F.P.C.*, 361 F. 2d 70 (D.C. Cir. 1966), the court upheld, in a *per curiam* opinion, a rate filing based upon a bilateral contract modification made after the initial rate filing.

[50] See discussion, *infra*, concerning conforming amendments.

[51] Issued in Docket No. RM79-12 on November 17, 1978, and December 28, 1978, respectively.

quarter? It is our intention that the blanket affidavit authorize collection of any contractually authorized price which is at or below the applicable maximum lawful price. We believe that an area rate clause does provide contractual authorization for the quarterly escalation. Accordingly, sellers who would under the proposal be foreclosed from collecting NGPA prices could, if their contracts permit, continue to collect the Opinion No. 770-A price as adjusted. Our final rule will make any necessary changes in our regulations in this respect.

V. INTRASTATE CONTRACTS

Both the statute itself and the legislative history of the NGPA provide some guidance concerning the operation of indefinite price escalator clauses in existing intrastate contracts.[52] Section 105(b)(3) addresses the question directly. Section 105(b)(3)(B) defines the term "indefinite price escalator clause," [53] and section 105(b)(3)(A) contains a limitation on the operation of such clauses after January 1, 1985. Questions have been raised, however, concerning other limitations on the operation of these clauses in existing intrastate contracts. In those cases where section 105(b)(1) is the applicable ceiling price, that is, where the contract price on date of enactment did not exceed the new natural gas price, and where no higher ceiling price under another section is applicable, indefinite price escalator clauses may be given effect according to their terms, so long as the resulting increase does not result in a price in excess of the new natural gas price. Of course, the price increase may exceed the new natural gas price in the event a well qualifies for a higher price such as the stripper gas price under section 108 of the NGPA.

The legislative history further provides that such clauses in intrastate contracts are not triggered by the "mere enactment" of the NGPA, but that actual sales at the NGPA prices will trigger such clauses.[54] The Statement of Managers does not define "indefinite price escalator clause" but presumably the reference is to the term as defined in section 105(b)(3)(B).

If section 105(b)(1) of the NGPA is the applicable maximum lawful price and no higher ceiling price applies, then escalator clauses may increase the contract price in accordance with the contract terms (as in effect on November 9, 1978) but not to a level in excess of the new natural gas price under section 102 of the NGPA. The section 102 price limitation would not apply to a well or wells which are eligible for a higher NGPA price. In this regard, we point out that, consistent with our proposal regarding area rate clauses, an FPC clause which is worded in the same fashion as a permissible area rate clause would not provide contractual authorization to charge and collect NGPA prices. A clause in an existing intrastate contract which by its terms is triggered by Congressional action would, however, in our opinion, provide such authorization. Inasmuch as intrastate contracts are not subject to any rate change filing requirements or protest procedures, the Commission will leave the interpretation of these clauses initially to the parties; however, under our proposal, a seller violates the NGPA, and subjects himself to subsequent enforcement action, if an interpretation of an escalator clause is inconsistent with the terms of the clause.

In the case of gas which is not committed or dedicated on November 8, 1978, the parties may effect bilateral modifications of existing contracts, so long as the new contract price does not exceed the applicable maximum lawful price. In other words, the parties may amend their contracts to collect prices determined under sections 102, 103, 107, and 108, to make interim

[52] The Statement of Managers (p. 82) explains the effect of section 105(B)(1) in the following terms: . . . the price under the contract may escalate through the operation of both fixed price escalator clauses and indefinite price escalator clauses in existence as of the date of enactment, but the price may not exceed the new gas price.

[53] The text of the definition appears in note 3. See also, section 313 of the NGPA.

[54] At page 83 of the Statement of Managers the following statement appears: The conferees do not intend that the mere establishment of the ceiling prices under the NGPA shall trigger indefinite price escalator clauses in existing intrastate contracts. Once natural gas is sold pursuant to the ceiling prices under this act, such clauses would be activated as limited by this section.

collections under Part 273 of the Commission's interim regulations, or to collect the monthly escalation provided in section 105(b)(2). Of course, where section 105(b)(1) is the highest applicable maximum lawful price, the price charged for deliveries of gas cannot exceed the price under the terms of the contract as such contract was in effect on November 9, 1978, and thus such terms may not be modified by contractual amendment to collect a higher price under section 105(b)(1). Intrastate contracts may be amended to permit collection of a higher maximum lawful price than that established under section 105(b)(1) if the natural gas sold under that contract is determined to be eligible for a higher maximum lawful price.

VI. EXPLANATION OF AMENDMENTS TO THE REGULATIONS

As noted above, the action we are proposing today concerning price escalation clauses would require us to amend 18 CFR 270.205, as well as certain other regulations. An explanation of the amendments follows.

A. *Section 270.205* would be amended as set forth below. The title of the section is changed to "Contractual authorization to collect NGPA rates." The new rule is divided into three paragraphs. Proposed § 270.205(a), applicable to existing interstate contracts, provides that price escalator provisions in existing intrastate contracts, be they permissible or impermissible, will not permit the collection of NGPA prices. With respect to permissible clauses, we hold that they do not, by their terms, apply to such prices. Impermissible clauses are given no effect unless the Commission has expressly waived the provisions of § 154.93.

Section 270.205(b), "Existing intrastate contracts," would provide that price escalator clauses may operate according to their terms, provided that they do not have the effect of allowing the collection of a price in excess of the applicable ceiling price. The rationale for this rule is more fully described above. Section 270.205(c), entitled "Modification of existing contracts," would provide that parties may amend their contracts to provide specific authorization, to collect applicable NGPA prices. The section would also reflect the rule applicable to a first sale of natural gas where the highest applicable maximum lawful price is established under section 105(b)(1) of the NGPA.

B. *Section 154.93.* As indicated above, we would amend § 154.93 to provide that a clause in interstate contracts which permits collection of any applicable maximum lawful price, or of the highest maximum lawful price under the NGPA, will be accepted for filing and will be permitted to operate according to its terms. This amendment is necessary to give effect to our policy concerning contract modifications. Thus, we would add a new § 154.93(d) to our existing regulations.

C. *Section 154.94(h) [Order No. 15, 15-A Procedures].* Revision of our blanket affidavit and protest procedures provided for in Orders 15 and 15-A would be necessary. We stated in Order 15-A that the filing of a blanket affidavit does not permit the collection of a maximum lawful price which is not contractually authorized. We emphasize that blanket affidavits filed solely on the basis of an area rate clause are not supported by the requisite contractual authority. In the event collections have been made based on affidavits which are not supported by contractual authorization, the Commission would permit parties to those transactions to file contract amendments on or before May 1, 1979.

If amendments are not filed, the Commission would require any revenues collected in the absence of contract authorization to be refunded. In order to implement these requirements we would amend § 154.94(h)(4) to add a requirement that the contractual provisions authorizing the rates to be charged under the blanket affidavit be filed contemporaneously with the filing of the blanket affidavit. However, for any blanket affidavit filed before April 1, 1979, we would permit such contractual provisions to be filed on or before May 1, 1979. These contractual provisions may provide an effective date coincident with the effective date of the blanket affidavit which it supports.

We also propose to amend § 154.94(h)(8) to provide that protests in the case of affidavits filed prior to April 1, 1979, may be filed within

thirty days of the filing of the contractual authorization.

VII. PROCEDURES

The Commission heretofore has considered the matters raised in connection with price escalator clauses in two different rulemaking proceedings—one relating to the Commission's interim regulations implementing the NGPA, and the other relating to filing requirements, contractual authorization, and protest procedure under the Natural Gas Act (Orders 15 and 15A). In addition, comments were separately requested on certain specific issues relating to indefinite price escalator clauses. In light of the importance of its policy decision respecting price escalator clauses, and the fact that a number of issues which were not specifically addressed in any of the prior requests for comment have been raised—in particular, those relating to our blanket affidavit procedure, retroactive contract amendment, and the authority of pipelines to pass through cost increases attributable to contract modification—the Commission has determined to issue a single notice of proposed rulemaking which contains the complete text of its proposed rules and an explanation of the legal basis for the proposal.

Comments by interested persons are requested on the proposed rule contained in this notice. In addition, the Commission specifically requests comment on each of the three principal alternatives which it has heretofore considered. These alternatives include: (1) an approach which would interpret area rate clauses contained in interstate contracts to permit collection of the section 104 prices derived from area and national rates; (2) the position discussed by the Commission in public session which would interpret area rate clauses as authorizing collection of the section 103 and 104 prices; and (3) the position which would interpret area rate clauses as authorizing collection of all NGPA prices.

A. *Written comment procedures.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to 4:30 p.m., E.S.T., February 27, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79-22.

B. *Public hearing procedures.* A public hearing concerning this proposal will be held in Washington, D.C. on February 27, 1979, beginning at 9:30 a.m., and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on February 22, 1979.

Request to participate in the hearing should include a reference to Docket No. RM79-22, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m. on February 26, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the

conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

The Commission intends to take final action on this proposal on March 1, 1979.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Natural Gas Policy Act of 1978, P.L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, P.L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to amend Parts 154, 270 and 273 of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.[*]

KENNETH F. PLUMB,
Secretary.

1. Section 154.93 is amended by striking out "and" at the end of paragraph (b-1), and by adding a new paragraph (b-2) to read as follows:

§ 154.93 Rate schedule defined.

* * * * *

(b-2) Provisions entered into on or after December 1, 1978, which permit a seller to charge and collect for deliveries on or after December 1, 1978, any applicable maximum lawful price prescribed by or under the Natural Gas Policy Act of 1978 (including any price authorized to be collected under Part 273 of this chapter); and

* * * * *

2. Section 154.94 is amended in paragraph (h)(4) by adding a new clause (iii) to read as follows:

§ 154.94 Changes in rate schedules.

* * * * *

(h) * * *
(4) * * *

(iii) Evidence of contractual authorization for collection of the rates for a first sale under the affidavit shall be filed contemporaneously with the filing of the affidavit, except that with respect to an affidavit filed prior to April 1, 1979, such evidence may be filed with the Commission and concurrently served upon each affected purchaser before May 1, 1979. Contractual authorization for a rate for a first sale may provide for an effective date coincident with the date on which the affidavit is effective under clause (i) or (ii) with respect to such sale.

§ 154.94 [Amended]

3. Section 154.94 is amended in paragraph (h)(7) by adding at the end thereof the new sentence: "For special rules respecting contractual authorization to collect NGPA rates, see § 270.205."

4. Section 154.94 is amended in paragraph (h) by revising subparagraph (8) to read as follows:

(h) * * *

(8) Any protest to an affidavit required to be filed under this paragraph shall be filed no later than thirty days after the filing of the affidavit, or, in the case of an affidavit filed before April 1, 1979, within thirty days after the filing of the evidence of contractual authorization to collect the rate under the affidavit.

* * * * *

5. Section 270.205 is amended to read as follows:

§ 270.205. Contractual authorization to collect NGPA rates.

(a) *Existing interstate contracts.* A contractual provision, permitted by § 154.93(b-1) of this chapter (relating to area rate clauses) contained in an existing contract for a first sale of natural gas to which the Natural Gas Act applies, does not constitute contractual authorization to charge and collect any maximum lawful price prescribed by or under the NGPA (including any price, the collection of which is authorized by Part 273 of this subchapter). Any contractual provision for a change in price in such a contract (executed after April 3, 1961), which by its terms permits collection

[*] Commissioners Smith and Sheldon dissenting.

of such prices, does not constitute contractual authorization to charge and collect such prices unless the Commission has permitted such contractual provisions to take effect by expressly waiving the provisions of § 154.93 which would make such provision inoperative.

(b) *Existing intrastate contracts.* Contractual provisions for a change in price in an existing contract (other than a contract to which paragraph (a) applies) may operate according to the terms of such provisions except that such provisions are not operative to authorize a seller to charge and collect an amount in excess of the highest applicable maximum lawful price prescribed by or under the NGPA (including any price collection of which is authorized by Part 273).

(c) *Modification of existing contracts.* The NGPA does not prohibit parties to existing contracts for the first sale of natural gas from amending or modifying such contracts to permit the seller to charge and collect any applicable maximum lawful price established by or under the NGPA (including any price collection of which is authorized by Part 273). If natural gas sold under such contract is subject to section 105(b)(1) of the NGPA and qualifies for no higher maximum lawful price, no amendment or modification of such contract may provide authorization for a seller to charge and collect a price which exceeds the price under the terms of the contract as in effect on November 9, 1979.

6. Section 273.104 is amended by designating the existing text as paragraph (a) and by adding a new paragraph (b) to read as follows:

§ 273.104 Cross reference.

* * * * *

(b) For special rule relating to contractual authorization to make interim and retroactive collections, see § 270.205.

SMITH, COMMISSIONER, AND SHELDON, COMMISSIONER, DISSENT TO THE COMMISSION'S ACTION

The need for expedition in resolving the NGPA questions relating to rate change clauses is unquestioned and has been recognized by the Commission.[1] The Commission has adequate material in its rulemaking record to decide the questions before it. The Proposed Rule is not supported by that record, nor by any compelling policy considerations. The following concerns with the Rule as drafted are outlined to assist interested persons to either dispel misconceptions expressed in the Rule, or to further develop alternatives to the proposal, or to indicate to us that the concerns are misplaced.

The Proposed Rule concludes that neither the standard area rate clause in an interstate gas sales contract nor its intrastate counterpart, an FPC clause, provide contractual authorization for a seller to charge and a purchaser to pay NGPA prices for first sales of natural gas. It appears that the basis for this conclusion was the failure of Congress to follow *Permian* methodology in establishing NGPA incentive prices that are, according to the draft Rule, "Too high" and not "cost based." The Rule and its rationale are, in their current state, subject to a number of deficiencies.

1. The Rule, as drafted, fails to recognize the existence of, much less give reasoned consideration to, the overwhelming majority of views and comments, oral and written, which have been elicited from concerned parties ostensibly to assist the Commission in arriving at a decision in this matter. These comments by buyers and sellers of natural gas, as well as by members of Congress involved in the passage of the NGPA,

[1] What the Commission should do in response to the inquiries raised concerning § 270.205 first appeared on the Commission's public meeting agenda in mid-December 1978. By direction of the Commission, the Smith memorandum dated December 20, 1978 and a draft order by the Office of General Counsel dated December 28, 1978 were placed in the public file for comments. Both documents stated there was a need for an expeditious resolution of the questions presented. Further, the order of January 12, 1979 setting oral argument noted: because of the importance of prompt resolution of the uncertainties surrounding the question of the effects of the NGPA on area rate clauses particularly in light of the need for producers to bill their customers for December 1978 deliveries, the Commission shall set this matter for oral argument before the full Commission. (footnote omitted)

This sentiment was echoed at the oral argument held on January 19, 1979 (Tr. 4). Protestations aside, the instant notice of proposed rulemaking causes additional delay. The December billing period has come and gone. While a postponement by the majority of the adoption of an unsupportable result is welcome, nonetheless the Commission must reach a decision on this question and could have done so on the basis of the record already compiled.

expressed views contrary to the conclusions reached in the Proposed Rule, and are almost wholly ignored.[2] This omission leaves the proposed Rule bereft of the kind of reasoned consideration necessary to sustain it on judicial review. While this cavalier treatment of the Commission's process of eliciting comment cannot be encouraging to those who are once more saddled with the obligation to prepare written and oral comments, it is an injury to procedural due process that can and should be healed in the subsequent consideration of the next set of resubmitted views.

2. The Proposed Rule, in uncertainly tracking its central theme that NGPA prices are "high", not "cost based", and were not established on the basis of *Permian* methodology, yaws into pronouncements not within the jurisdiction of the Commission to make. Two illustrations are proffered. An incredulous reader of the Proposed Rule will learn that a contractual provision specifically providing for payment of such prices as may be prescribed by Congress is *not* contractual authorization for the payment of prices prescribed by Congress, since such a clause is "variant." The Proposed Rule reached this result by overstating the potency of the regulatory program contemplated in 18 CFR § 154.93 and its reach over any clause which might be deviant or variant. Congressional rate prescription clauses were never within the power of the Commission to prohibit by regulation. The Commission cannot limit by its regulations powers greater than that which it exercises. Deregulation clauses[3] and Congressional rate prescription clauses spoke to circumstances in which the Commission's regulatory powers had been superseded, and the Commission could no more prohibit parties from contracting for these contingencies than could it require parties to forego judicial review of its orders or regulations. Similarly, the jurisdictional basis for asserting that FPC clauses in intrastate contracts cannot, after interstate rates are charged and collected, provide contractual authorization for charging the appropriate NGPA rates, appears questionable, and outside the sphere of authority in which the Commission may speak to the meaning of its own regulations. Contract law, not the Commission's regulations, controls here.

3. It is far from certain that the Proposed Rule can deliver on the assurance it seemingly proffers interstate pipelines, who are subject to utility regulation, that they may voluntarily consent to pay producers and recover from ratepayers higher prices than they are obliged to pay. The Rule attempts to provide this assurance by promising that the Commission will take no action to challenge flowthrough of such additional charges to ratepayers on the basis that voluntary payment does not constitute an abuse of such pipeline's responsibility to its customers. The final Rule, in addition to clarifying what "arms length" means, should deal with the question whether members of a future Commission would be legally bound by the opinion of some members of the present Commission. Even if future Commissions afford comity to the views of their predecessors, intervenors in PGA cases (such as some parties commenting in this proceeding who did not agree that modifications are permissible) may not

[2] Views leading to a conclusion on contractual authorization different to that set out in the proposed rule were submitted by pipelines (Panhandle Eastern Pipeline Company, Columbia Gas Transmission Corporation, United Gas Pipe Line Company, Michigan Wisconsin Pipe Line Company, Houston Natural Gas Corporation), producers (Indicated Producers, Mitchell Energy Corporation, Phillips Petroleum Company, Damson Oil Corporation, Pelto Oil Company, Grace Petroleum Corporation, Samson Resources Company, Northern Michigan Exploration Company, Mesa Petroleum Company, Northwest Arkansas Producers Group, Chapman Exploration Inc., William M. Fuller, Inexco Oil Company, Murphy Oil Company), U.S. Senators (Pete Domenici, Bennett Johnston), Congressman (Clarence Brown), and associations (Interstate Natural Gas Association of America, Texas Independent Producers and Royalty Owners Association, Ohio Oil and Gas Association, Independent Oil & Gas Association of West Virginia). Views supportive of the result reached in the proposed rule were set out by New York Public Service Commission, California Public Utilities Commission, Stauffer Chemical Company, Consolidated Gas Supply Corporation (in part), Associated Gas Distributors, and Western Farmers Electric Cooperative, *et al.* Chairman John Dingell's comments revealed that the conclusions of the Proposed Rule were not mandated by the legislation.

[3] The narrow focus of the Proposed Rule on the exact wording of only § 154.93 ignores the long-standing policy of the Commission of allowing the inclusion in interstate contracts of so-called deregulation clauses. These clauses were permissible since they speak to a time when the Commission's authority over the contract would be nonexistent. Deregulation clauses do not provide for the payment of cost-based prices prescribed by the Commission in area rate proceedings, but these clauses were permitted to be included in the contracts and will become effective for rate purposes upon deregulation. This leads to the conclusion that the argument of the Proposed Rule is incorrect that all price change provisions in interstate contracts were treated consistently by the FPC as only relating to cost-based area rates.

be estopped from raising the question. Industrial customers objecting to a pipeline's gratuitous agreement to pay a higher rate which will be incrementally priced to them do not appear to have been foreclosed from raising such objections. Similarly, stockholders who may question management prudency in deciding to pay more for that which, under the Proposed Rule's central theme, they have contracted to get for less, may not be satisfied with the answers they are provided.

4. The Proposed Rule truncates its treatment of the evolution of producer ratemaking with Opinion Nos. 770 and 770-A. Specifically, the Proposed Rule does not negate the strong implication that the NGPA was meant as a substitute for what would otherwise have been another Commission biennial review.

In Opinion Nos. 770 and 770-A,[4] the Commission set rates for production from wells spudded between January 1, 1975, and December 31, 1976. Section 2.56a(m) of the Commission's Regulations, promulgated in Opinion No. 770-A, deliberately and without qualification stipulated that a new proceeding would commence to develop rates to apply to, *inter alia*, all wells drilled after January 1, 1977, and before January 1, 1979. This commitment was to induce producers to explore for, find, and sell natural gas to the interstate market rather than to defer such activity until the establishment of higher prices. This procedure, Docket No. RM77-13, was actually commenced by the FPC on March 1, 1977, but suspended by notice of September 30, 1977. It was during this period and thereafter that the Congress was considering the NGPA.

Had the Congress not chosen to exercise its jurisdiction to set rates and enacted the NGPA, the Commission prescribed rates for the 1977-1978 bienium would now be in effect. Those rates would reflect cost increases experienced since the close of the Opinion No. 770 biennium. Producers would be collecting those rates pursuant to their area rate clauses. Instead, Congress acted to set rates. In the first instance Congress adjusted existing rates, as the Commission itself had done in Opinion Nos. 770 and 770-A by increasing the 1973-1974 vintage rates originally set in Opinion Nos. 699 and 699-H.[5] Secondly, Congress set ceiling prices in §§ 102, 103, and 107 for wells drilled after February 19, 1977, a date which is so nearly coincident with the Docket No. RM77-13 biennium vintage as to demonstrate the close relationship of the Congressional action to what would otherwise have been a Commission ratemaking proceeding.

The purpose of this discussion is to show that the Congress' enactment of the NGPA was derivative of the timing and type of action that the Commission would have taken had it carried to fruition its ratemaking proceeding in Docket No. RM77-13.

The parallels are obvious but not surprising, for the common denominator is that ratemaking is a legislative endeavor. By enacting the NGPA, the principal, Congress, which had previously delegated one of its powers to the Commission, its agent, superseded that authority and itself acted. The Proposed Rule's assertion that the Congressional action failed to follow *Permian* methodology may effectively deny to Congress its right to exercise its unconditional legislative power to make utility rates. It also petrifies the Opinion No. 770 rates for those sellers who responded to pleas for interstate gas sales in 1977-1978 and spudded wells during that period, since there is no suggestion that the Commission will now revitalize Docket No. RM77-13 and set about the painful process of establishing a just and reasonable rate for wells spudded between January 1, 1977, and November 30, 1978.

The Proposed Rule may therefore deny to interstate sellers the cost based rates it so reveres, since all an interstate seller of gas from a well spudded after January 1, 1977 can obtain, without a contract modification, is the Opinion No. 770 rate, which is now $1.52 per Mcf. The Commission established its precendent for this situation in 1976 when it had to decide whether wells spudded between January 1, 1975—the beginning of the costing biennium—and July 26, 1976—the issue date of Opinion No. 770—would qualify for the new rate. In Opinion No. 770-A, the Commission stated: The contention of APGA that qualifying gas dedicated prior to July 27, 1976 'does not cost $1.42 to produce' is contrary to the evidence, which clearly shows that just the opposite is true. Those producers that have drilled wells and dedicated gas therefrom between January 1, 1975, and July 27, 1976, did so with knowledge of the Commission's previously announced intention to establish new, cost-based rates for such gas, and thus in anticipation of a rate commensurate with the higher costs incurred since January 1, 1975. Receipt of revenues from such a rate has already been delayed (and thus forever denied) for over 18 months of the period to which the rates should have applied. To deny those producers the just and reasonable cost-based rate henceforth would be in

[4] 56 FPC—(1976), *rehearing*, Opinion No. 770-A, 56 FPC—, *aff'd, The Second National Natural Gas Rate Case, (APGA* v. *FPC*, 516 F. 2d 1016 (D.C. Cir. 1977)), *cert. denied*,— U.S. —(1978).

[5] 51 FPC 2212 (1974), *rehearing*, Opinion No. 699-H, 52 FPC 1604, *aff'd, Shell Oil Co.* v. *FPC*, 520 F.2d 1061 (5th Cir. 1975), *cert. denied sub nom., Calif. Co.* v. *FPC*, 426 U.S. 941 (1976).

violation of the Natural Gas Act and thus contrary to the overall public interest.[6]

On appeal, this decision was specifically upheld.[7] The unfortunate efect of the Proposed Rule is to reward producers who delayed exploration and development activity, or deferred signing contracts until higher prices were established, and penalize those who provided gas to the interstate market believing that the regulatory process would operate as it had before, and that area rate clauses would eventually enable them to collect those prices the government said were just and reasonable.

5. A central misgiving about the Proposed Rule as drafted is its insistence that Congress must exercise its Commerce Clause[8] powers to establish rates subject to the same NGA limitations it imposed on the Commission. That ratemaking is a legislative function is an established rule of law.[9] Congress assigned "jurisdiction in the premises" to the Federal Power Commission in 1938 by enactment of the Natural Gas Act.[10] It allowed the Commission to exercise this power until it determined to pre-empt the authority and act itself. Congress, in enacting NGPA, chose to supplant Commission jurisdiction, and it acted after, or in succession to, the period in which Commission jurisdiction prevailed. To cavil at the manner in which it acted on the basis that it failed to follow *Permian* methodology is analagous to finding fault with it for not having prepared an Environmental Impact Statement.

Area rate clauses were drafted in recognition of the fact that since 1954 when producer regulation began,[11] the government has set the rate at which interstate sales for resale may be made. One comment submitted in the record before the Commission summarizes the intent of the area rate clause and the relationship of private contract to federal regulation as follows: • • • [P]arties to interstate contracts generally believed that some form of governmental action would occur. The purpose of the area rate or FPC clauses was simply to permit the producer who committed his gas to the interstate market prior to such action occurring to benefit from such action provided that by governmental decision, he was otherwise permitted to do so. In short, parties agreed to make pricing a matter of governmental decision under circumstances where government chose to act."[12]

There is serious question whether the Proposed Rule reflects an understanding of this relationship.

In conclusion, we believe the appropriate course of action would have been for the Commission to adopt an order disposing of the questions it has addressed. We dissent to the course of action elected by the majority which establishes further procedures essentially duplicative of those that have gone before.

The majority, and thus the Commission, has selected its course of action. The foregoing comments represent an effort to frame the further proceeding in a manner which can allow the Commission to bring it to a satisfactory conclusion. We do not necessarily disagree with the concepts set out in the Proposed Rule: that NGPA rates are "relatively high," that a bargaining process has potential for enhancing consumer benefits, and that the NGPA rate for stripper wells exceeds that contemplated by parties to an older contract. We do, however, have reservations about the Commission's remaining authority to found a Rule upon those concepts.

DON S. SMITH,
Commissioner.

GEORGIANA SHELDON,
Commissioner.

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[6] 56 FPC —, mimeo pp. 13-14.

[7] *The Second National Natural Gas Rate Cases, Supra* n. 4, 567 F.2d at 1063.

[8] U.S. Const., Art. I, § 8, clause 3.

[9] *Prentis* v. *Atlantic Coast Line Co.*, 211 U.S. 210, 226 (1908). *See also, Munn* v. *Illinois*, 94 U.S. 113, 133-134 (1877); *Ohio Valley Co.* v. *Ben Avon Borough*, 253 U.S. 287, 289 (1920); *Morgan* v. *United States*, 279 U.S. 468, 479 (1936); *Colorado Interstate Gas Co.* v. *FPC*, 324 U.S. 581, 589 (1945).

[10] 15 USC § 717(a).

[11] *Phillips Petroleum Co.* v. *Wisconsin* (*Philips I*), 347 U.S. 672 (1954).

[12] Written comments of Michigan Wisconsin Pipe Line Company.

¶ 32,009 Hydroelectric Projects

44 F. R. 12432 (March 7, 1979).

[Docket No. RM 79-23]

HYDROELECTRIC PROJECTS

Regulations Prescribing General Provisions for Preliminary Permit and License Applications; REgulations Governing Applications for, Amendments to, and Cancellation of Preliminary Permits.

MARCH 5, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission gives notice that it proposes to amend its regulations concerning preliminary permits and licenses for hydroelectric projects under Part I of the Federal Power Act. The amended regulations prescribe technical filing requirements and evaluation procedures applicable to both preliminary permit and license applications. The amendments also affect the regulations pertaining specifically to the content of preliminary permit applications, amendments to preliminary permits, and cancellation of preliminary permits.

DATES: Comments are due by April 9, 1979.

FOR FURTHER INFORMATION:

Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-4166.

SUPPLEMENTARY INFORMATION: Notice is hereby given that the Federal Energy Regulatory Commission (Commission) proposes to amend certain of its regulations concerning preliminary permits and licenses for hydroelectric projects under Part I of the Federal Power Act (Act). The amended regulations prescribe technical filing requirements and evaluation procedures applicable to both preliminary permit and license applications. The amendments also affect the regulations pertaining specifically to the content of preliminary permit applications, amendments to preliminary permits, and cancellation of preliminary permits.

I. BACKGROUND

Seeking to respond and lend encouragement to the recent heightened interest in hydroelectric development, Congress provided in Title IV of the Public Utility Regulatory Policies Act (PURPA) component of the National Energy Act for a program whereby the Secretary of Energy will grant loans for feasibility studies and for construction of small hydroelectric projects (installed capacity of 15 MW or less) located at existing dams. The Commission is charged under Section 405 of PURPA with establishing simple licensing procedures for projects eligible under the PURPA provisions.

In the interest of acting more promptly on all license applications, and in anticipation of the enactment of PURPA, the Commission determined in 1978 to carry out a thorough reform of its requirements and procedures for license applications. The first phase of this reform was instituted in September 1978, with issuance of a rulemaking on the "shortform" license procedures applicable to all "minor" projects (installed capacity of 1.5 MW or less). See Order No. 11, Docket No. RM78-9, 43 FR 40215 (September 11, 1978).

The second phase of the reform will cover all "major" projects (installed capacity greater than 1.5 MW) where at least the dam(s) and reservoir(s) are already in existence. The Commission intends to consider a proposed rulemaking on this phase by April 1, 1979. A third and final phase will cover all major projects which must be constructed in their entirety.

The revisions contemplated in this three-stage reform pertain primarily to the content of license applications. Maximum efficiency cannot be attained, however, unless the uncertain-

ty regarding such technical and procedural matters as form, subscription and verification, service, number of copies, correction of deficiencies, and evaluation of competing applications is eliminated. Accordingly, we propose to amend and consolidate the general provisions governing these requirements and procedures for all preliminary permit and license applications.

The amended regulations are intended to make the Commission's technical filing requirements and procedures easier to identify and comprehend. The regulations are also intended to make clear that diligence is expected, not only of the Commission staff, but of initial applicants and those who would file competing applications, as well.

A well-rounded program of licensing reform must also reach the requirements governing preliminary permits. As enunciated in sections 4(f) and 5 of the act, 16 U.S.C. 797(f) and 798, the purpose of a preliminary permit is to secure for the permittee priority of application for a license for a project while the permittee obtains the data and performs the acts required to determine the feasibility of the project and support an application for a license. A preliminary permit is not a prerequisite to a license, and therefore is sought on a voluntary basis. The protections afforded by permits result in frequent permit applications, however. In view of the close nexus between preliminary permits and licenses, the Commission proposes to amend the regulations concerning the substance of preliminary permit applications, amendments to preliminary permits, and cancellation of preliminary permits, as well.

The amended regulations are designed to minimize the filing burden on applicants for preliminary permits while requiring sufficient information to enable the Commission to carry out its responsibilities under the Act. The regulations also make clear the purpose of a permit and the consequences of failure to carry out that purpose. We believe these changes will further facilitate ultimate licensing of small hydroelectric projects at existing dams, in accordance with section 405 of PURPA.

We now proceed to a description and explanation of the specific regulations.

II. Description of Proposed General Provisions

§ 4.30 Who may file

Section 4.30 specifies who may file an application for a preliminary permit or a license. Since any permittee is a potential licensee, the qualifications must be the same. The section therefore paraphrases, in somewhat streamlined form, the provisions of Section 4(e) of the Act, 16 U.S.C. 797(e), specifying who may obtain a license. In recognition of the priority afforded by a preliminary permit, § 4.30 also provides that the Commission will not entertain an application for a preliminary permit for a project which would conflict with a project for which a preliminary permit is outstanding, or for which there is a pending license application filed by a permittee during the term of its permit. Nor will the Commission entertain an application for a license for a project which would conflict with a project for which a preliminary permit has been issued, until either the permittee files an application for a license or the permit expires, whichever occurs first.

§ 4.31 Acceptance for filing or rejection

Section 4.31 governs acceptance and rejection of preliminary permit and license applications. Section 4.31(a) provides references to the specific minimum requirements which an application must meet. Besides incorporating certain provisions of the Commission's rules of practice and procedure by reference, the section requires conformance with specific subsequent provisions governing the substance of an application, according to its type.

Section 4.31(b) requires that an original and nine copies of the application be filed with the Secretary. The treatment of maps and drawings included in license applications is also prescribed.

Section 4.31(c) prescribes the actions which the Commission or its delegate will take upon receipt of a conforming application, including issuance of public notice and, in the event that lands of the United States are affected, notification of the appropriate federal office under Section 24 of the Act, 16 U.S.C. 818.

Under § 4.31(d), a deficient application may be rejected outright, or the applicant may be afforded additional time, not to exceed 45 days in the case of a preliminary permit application, or 90 days in the case of a license application, to correct the deficiencies. If the deficiencies are not corrected within the time provided, then the application will be rejected. Moreover, § 4.31(e) provides that an application will be deemed "accepted for filing" as of the time of the initial submittal, but only if it is made whole within the time prescribed by the Commission or its delegate. Under current practice, an application is recorded as filed and assigned a project number, however deficient it may be, when the first document is received by the Secretary. The Commission staff must often keep track of incomplete applications for protracted periods while making repeated requests that deficiencies be corrected. The revised regulations would place a greater burden of diligence in submitting a conforming application on the applicant, and would free the Commission staff to concentrate its efforts on viable applications. Rejections based on deficiencies would be without prejudice to refiling.

Section 4.31(f) provides that an applicant may be required to provide any additional information or documents that are deemed necessary or desirable to process the application. These materials would go beyond the threshold requirements for a conforming application, and their absence from the initial application would therefore not prevent acceptance of the application for filing. Failure to provide the information requested, however, would be sufficient ground for holding the proceeding in abeyance, dismissing the application, or taking other appropriate action. In certain instances, an applicant may also be requested to provide copies of the complete application to specified persons or agencies.

Finally, § 4.31(g) provides that a prospective applicant may submit preliminary copies of its application to the Director, Division of Licensed Projects, for the purpose of obtaining staff advice concerning the sufficiency of the application. Conferences between applicants and the staff regarding deficiencies or other application-related matters are also permitted. Once again, the object of the regulation is to avoid application deficiencies and consequent delays.

§ 4.32 SPECIFICATIONS FOR MAPS AND DRAWINGS

Section 4.32 provides the specifications which must be followed in preparing all maps and drawings filed with applications, except as otherwise prescribed. This section supplants the existing § 4.42. All references to § 4.42 elsewhere in the regulations will therefore be amended to refer to § 4.32.

§ 4.33 DISPOSITION OF CONFLICTING APPLICATIONS

Section 4.33, which has no corresponding provision among the existing regulations, governs conflicting applications for preliminary permits and licenses. The provisions of this section are intended to minimize the uncertainty and delay that may attend disposition of applications contemplating development of the same resource. Under the current regulations, there is no time limitation on the submittal of competing applications. If the Commission staff has fully processed an initial application, and is on the verge of recommending action to the Commission, a last-minute competing application may render the entire effort futile. A series of such competing applications could delay the matter indefinitely.

The proposed § 4.33(a) permits the filing of a competing application, but requires that the application, or a notice of intent to file such an application, be submitted prior to the end of the period prescribed in the public notice of the *initial* application for preliminary permit or license for filing of protests and petitions to intervene. Under § 4.33(c), if a timely notice of intent is submitted, the prospective applicant will be afforded an additional 60 days beyond the end of the public notice period to submit the application. Thus, if no competing application or notice of intent is forthcoming during the prescribed period, the Commission staff may proceed with its work on the initial application without fear of wasted effort or delay. Even if a competing application is filed, there is greater certainty with respect to the

applicants among whom the Commission will ultimately have to choose, and the proceeding may go forward free of disruption.

Section 4.33(b) specifies the requirements for form and content of a notice of intent to file a competing application. Section 4.33(d) provides that competing applications must be self-contained and must conform to the requirements of § 4.31.

Under § 4.33(e), if a pending application for a preliminary permit conflicts with a pending application for a license, and the applicant for a license has demonstrated its ability to carry out its plans, then the Commission will favor the applicant for a license.

Section 4.33(f) sets forth the bases for selection between or among competing applicants when there are two or more applications for a preliminary permit, or two or more applications for a license by applicants who are not permittees under outstanding preliminary permits. These provisions reflect the provisions of Section 7(a) of the Act, 16 U.S.C. 800(a), including the concept of state or municipal preference and the concept that, where the preference does not apply, the applicant whose plan is "best adapted" will prevail. The proposed regulation injects the additional concept that, all other things being equal, the principle "first in time, first in right" will apply. We are not ruling here on the question whether the state or municipal preference under section 7(a) applies in a relicensing proceeding under section 15(a) of the Act, 16 U.S.C. 808(a). That question is the subject of a pending proceeding on a petition for declaratory order in *City of Bountiful, Utah, et al.*, Docket No. EL78-43.

Finally, § 4.33(g) provides the bases for selection between or among competing applicants when there are two or more applications for a license, and one of the applications was filed by a permittee under an outstanding preliminary permit. The latter applicant is entitled to priority status.

§ 4.34 HEARINGS ON APPLICATIONS

Section 4.34 provides that the Commission may order a hearing on an application on its own motion or the motion of any party in interest. Hearings are to be limited to the issues prescribed by order of the Commission.

III. DESCRIPTION OF PROPOSED REGULATIONS CONCERNING PRELIMINARY PERMITS

§ 4.80 APPLICABILITY AND PURPOSE

This section states that §§ 4.80 through 4.83 pertain to preliminary permits under Part I of the Federal Power Act. The section also enunciates the sole purpose of a preliminary permit, as provided in section 5 of the Act.

§ 4.81 CONTENTS OF APPLICATION

Section 4.81 prescribes the information and documents which must be included in an application for a preliminary permit. Section 4.81(a) calls for an initial statement providing the identity and nature of the applicant, the name and location of the proposed project, and the proposed term of the permit.

The remainder of the information is to be provided in four numbered exhibits. Exhibit 1 (§ 4.81(b)) would include a description of the proposed project, including its principal structures and features and any lands of the United States that are affected. While the information need only be provided "to the extent possible," the degree of specificity and completeness of the description could have a bearing on the Commission's assessment of the applicant's ability to complete its preparations during the term of the permit, and on a comparison by the Commission of competing applications.

Exhibit 2 (§ 4.81(c)) would contain a study plan and work schedule. The plan would specify and describe the studies, tests, and plans that had already been carried out or prepared, as well as those projected for completion during the term of the proposed permit. A work schedule providing a timetable for the projected activities would be included with the plan. Two essential milestones in the schedule would be the interval at which the permittee will make a final determination regarding the technical, economic, and financial feasibility of the proposed project, and the interval at which the permittee will file an application for a license, if appropriate. A permit is meaningless if these milestones cannot be attained during its

term. The study plan and work schedule would help the Commission monitor the progress of its permittees and hold them accountable.

Exhibit 3 (§ 4.81(d)) would contain a statement of costs and financing. Applicants would be asked to estimate the costs of carrying out or preparing the studies, tests, and plans identified in Exhibit 2, and to state the expected sources and extent of financing for those activities. The Commission would thus have some basis for determining the applicant's financial ability to fulfill the purposes of the permit. The exhibit would also call for a description of the proposed market for the power generated at the project, including any available information concerning the revenues to be derived from sale of the power. This information would be significant to an assessment of the economic and financial viability of the project itself.

Exhibit 4 (§ 4.81(e)) would include a map or series of maps showing the location of the proposed project, the physical interrelationships of its principal features, a proposed project boundary, and any lands of the United States that are affected by the project. In order to ensure accuracy and uniform quality, applicants would be required to base the maps on U.S. Geological Survey topographical quadrangle sheets or similar planimetric maps of a state agency, if available.

§ 4.82 AMENDMENTS

Section 4.82 allows permittees to file applications for amendment of their permits. Amendments may include any extension of the term of the permit that does not cause the term to exceed three years. If an application for an amendment requests a material change in the project, public notice of the application will be given.

§ 4.83 CANCELLATION AND LOSS OF PRIORITY

Finally, § 4.83 makes clear that a permit may be cancelled for failure of the permittee to comply with the specific terms and conditions of the permit or for "other good cause shown, after notice and opportunity for hearing." Such cancellation will result in loss of the permittee's priority of application for a license for the project, as will expiration of the permit before a license application is filed. These provisions are intended to emphasize the consequences of failure to prosecute the plans and studies under the permit. This section is entirely new.

IV. Proposed Deletions

Besides revising, consolidating, and adding to the pertinent existing regulations, this rulemaking would eliminate certain of the regulations altogether. Sections 4.33 and 4.85 governing "issuance and acknowledgement of acceptance" of licenses and preliminary permits, respectively, have been deleted. The same general language is provided in standard ordering paragraphs in each license, and the Act does not require acceptance of a permit.

Section 4.86, which allows for some construction work on a proposed project during the term of the preliminary permit, has also been eliminated. There is no longer any doubt that construction work in advance of issuance of a license is inappropriate.

Finally, § 131.10, which prescribes a format for preliminary permit applications, has been deleted as superfluous. With each element of required information assigned to the initial statement or a particular numbered exhibit, the prescribed format is no longer needed.

V. Written Comment Procedures

The Commission invites interested persons to submit written comments on the matters proposed in this notice. An original and 14 copies of such comments should be filed with the Commission by April 9, 1979. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. All comments should refer to Docket No. RM79-23.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426. The Commission will consider all timely comments before acting on the matters proposed in this notice.

(Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Public Utility Regulatory Policies Act, Pub. L. 95-617, 92 Stat. 3117 *et seq.*; and Executive Order 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to amend Parts 4 and 16 of Subchapter B and Part 131 of Subchapter D, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

KENNETH F. PLUMB,
Secretary.

(A) Sections 4.30 through 4.33 are amended by deleting the existing sections and replacing them with the following:

APPLICATION FOR PRELIMINARY PERMIT OR LICENSE: GENERAL PROVISIONS

§ 4.30 Who may file.

(a) Any citizen, association of citizens, domestic corporation, municipality, or state may apply for a preliminary permit or a license for a water power project under Part I of the Federal Power Act.

(b) The Commission will not entertain an application for a preliminary permit for a proposed project which would develop, conserve, and utilize, in whole or in part, the same water resources that would be developed, conserved, and utilized by a proposed project for which a preliminary permit is outstanding, or for which there is a pending license application filed by a permittee during the term of its permit.

(c) The Commission will not entertain an application for a license for a proposed project which would develop, conserve, and utilize, in whole or in part, the same water resources that would be developed, conserved, and utilized by a proposed project for which a preliminary permit has been issued, until either the permittee files an application for a license or the permit expires, whichever occurs first.

§ 4.31 Acceptance for filing or rejection.

(a) Each application for a preliminary permit or a license must:

(1) Conform to the requirements of §§ 1.5, 1.14, 1.15, 1.16, and 1.17 of this chapter, except as otherwise prescribed in this part; and

(2) Contain all of the information and documents prescribed in the following sections of this chapter, according to the type of application:

(i) Preliminary permit: § 4.81;

(ii) License for a minor project: § 4.60;

(iii) License for a proposed major project: §§ 4.40 and 4.41;

(iv) License for a constructed major project: §§ 4.50 and 4.51;

(v) License for a transmission line: §§ 4.70 and 4.71;

(vi) New license for a licensed project: § 16.6; or

(vii) Nonpower license for a licensed project: § 16.7.

(b) Each applicant for a preliminary permit or a license must submit to the Secretary for filing an original and nine copies of the application, including full-size prints of all required maps and drawings. The originals (microfilm) of maps and drawings included in a license application (see § 4.32(a)) are not to be filed with the initial application, but will be requested pursuant to paragraph (c) of this section.

(c) When an application for a preliminary permit or a license is found to conform to the requirements of paragraphs (a) and (b) of this section, the Commission or its delegate will:

(1) Assign a project number to the application, unless the project has already been assigned a number;

(2) Notify the applicant that the application has been accepted for filing, specifying the project number assigned and the date upon which the application was accepted, and requesting (for a license application) the originals (microfilm) of required maps and drawings;

(3) Issue public notice of the application as required in the Federal Power Act; and

(4) If the project affects lands of the United States, notify the appropriate federal office of the application and the specific lands affected, pursuant to Section 24 of the Federal Power Act.

(d) Any application for a preliminary permit or a license that fails to conform to the requirements of paragraphs (a) and (b) of this section may be rejected. In the alternative, the applicant may be notified of the specific

deficiencies in the application and afforded additional time, not to exceed 45 days from the date of the notification in the case of an application for a preliminary permit, or 90 days from the date of the notification in the case of an application license, to correct the deficiencies. Deficiencies must be corrected by submitting an original and nine copies of the specified materials to the Secretary for filing within the additional time provided. If the application is then found to conform to the requirements of paragraphs (a) and (b) of this section, action will be taken in accordance with paragraph (c) of this section. If the application is found not to conform, it will be rejected.

(e) An application for a preliminary permit or a license will be deemed "accepted for filing" as of the time of the initial submittal to the Secretary if the Secretary receives all of the information and documents necessary to conform to the requirements of paragraphs (a) and (b) of this section within the time prescribed by the Commission or its delegate under paragraph (d) of this section.

(f) An applicant for a preliminary permit or a license may be required to submit any additional information or documents that the Commission or its delegate deems necessary or desirable to process the application. The information or documents must take such form, and must be submitted within such time, as the Commission or its delegate prescribes. An applicant may also be required to provide copies of the complete application, or any of the additional information or documents that are filed, to such person, agency, or other entity as the Commission or its delegate prescribes. If an applicant fails to provide additional information or documents or copies of submitted materials, as required, the Commission or its delegate may dismiss the application, hold it in abeyance, or take other appropriate action under this chapter or the Federal Power Act.

(g) A prospective applicant for a preliminary permit or a license may, prior to submitting its application for filing, seek advice from the Commission staff regarding the sufficiency of the application. For this purpose, five copies of the application should be submitted to the Director, Division of Licensed Projects. An applicant or prospective applicant may confer with the Commission staff at any time regarding deficiencies or other matters related to its application. All conferences are subject to the requirements of § 1.4(d) of this chapter governing ex parte communications. The opinions or advice of the staff will not bind the Commission or any person delegated authority to act on its behalf.

§ 4.32 Specifications for maps and drawings.

All required maps and drawings must conform to the following specifications, except as otherwise prescribed in this chapter:

(a) Each original map and drawing must consist of a print on silver 35mm microfilm mounted on Type D (3¼" by 7⅜₁₆") aperture cards. Two duplicates must be made of each original. Full-size prints of maps and drawings must be on sheets no smaller than 24 by 36 inches and no larger than 28 by 40 inches. A space five inches high by seven inches wide must be provided in the lower right corner of each sheet. The upper half of this space must bear the title, scale, and other pertinent information concerning the map or drawing. The lower half of the space must be left clear.

(b) Each map must be drawn to a scale no smaller than one inch equals 1,000 feet, and must show: (1) True and magnetic meridians; (2) state, county, and township lines; and (3) boundaries of reservations of the United States (see 16 U.S.C. 796(2)), if any.

(c) Drawings depicting project structures must be drawn to a scale no smaller than: (1) One inch equals 50 feet for plans, elevations, and profiles; and (2) one inch equals 10 feet for sections. Other drawings must be drawn to a scale appropriate to show the details required by pertinent regulations.

(d) Each map and drawing must be so drawn and lettered as to be legible when reduced to prints 10.5 inches in smaller dimension. Following notification to the applicant that the application has been accepted for filing (see § 4.31(c)), such reduced prints must be bound in each copy of the application which is submitted.

§ 4.33 Filing and disposition of conflicting applications.

(a) Any citizen, association of citizens, domestic corporation, municipality, or state may file an application for a preliminary permit or a license for a project which would develop, conserve, and utilize, in whole or in part, the same water resources that would be developed, conserved and utilized by a project for which a preliminary permit or license application has already been filed ("initial application"). Such an application, or a notice of intent to file such an application, must be submitted for filing on or before the last date for the filing of protests or petitions to intervene prescribed in the public notice of the initial application for a preliminary permit or a license issued under paragraph (c)(3) of § 4.31.

(b) Any notice of intent to file an application for a preliminary permit or a license that is submitted for filing under paragraph (a) of this section must conform to the requirements of §§ 1.14, 1.15, 1.16, and 1.17 of this chapter, and must include:

(1) The exact name and business address of the prospective applicant; and

(2) An unequivocal statement of intent to file an application for a preliminary permit or a license.

(c) Any prospective applicant who has filed a notice of intent which conforms to the requirements of paragraphs (a) and (b) of this section may file an application for a preliminary permit or a license. The application must be submitted for filing not later than 60 days beyond the last date for the filing of protests or petitions to intervene prescribed in the public notice of the initial application for a preliminary permit or a license.

(d) Any application for a preliminary permit or a license that is submitted for filing under this section must be self-contained and conform to the requirements of paragraphs (a) and (b) of § 4.31. The application will be treated in accordance with § 4.31.

(e) If a pending application for a preliminary permit and a pending application for a license propose projects which would develop, conserve, and utilize, in whole or in part, the same water resources, and the applicant for a license has demonstrated its ability to carry out its plans, then the Commission will favor the applicant for a license.

(f) If two or more applications for preliminary permits, or two or more applications for licenses by applicants who are not permittees under outstanding preliminary permits, are filed for projects which would develop, conserve, and utilize, in whole or in part, the same water resources, then the Commission will select between or among the applicants on the following bases:

(1) If both of two applicants are either a municipality or a state, or neither of them is a municipality or a state, then the Commission will favor the applicant whose plans are better adapted to develop, conserve, and utilize in the public interest the water resources of the region, taking into consideration the ability of each applicant to carry out its plans;

(2) If both of two applicants are either a municipality or a state, or neither of them is a municipality or a state, and the plans of the applicants are equally well adapted to develop, conserve, and utilize in the public interest the water resources of the region, taking into consideration the ability of each applicant to carry out its plans, then the Commission will favor the applicant whose application was first accepted for filing (see § 4.31(e));

(3) If one of two applicants is a municipality or a state, and the other is not, and the plans of the municipality or state are at least as well adapted to develop, conserve, and utilize in the public interest the water resources of the region, taking into consideration the ability of each applicant to carry out its plans, then the Commission will favor the municipality or state; or

(4) If one of two applicants is a municipality or a state, and the other is not, and the plans of the applicant who is not a municipality or a state are better adapted to develop, conserve, and utilize in the public interest the water resources of the region, taking into consideration the ability of each applicant to carry out its plans, then the Commission will inform the municipality or state of the specific reasons why its plans are not as well adapted and afford a reasonable period of time for the municipality or

state to render its plans at least as well adapted as the other plans. If the plans of the municipality or state are rendered at least as well adapted within the time allowed, then the Commission will favor the municipality or state. If the plans of the municipality or state are not rendered at least as well adapted within the time allowed, then the Commission will favor the other applicant.

(g) If two or more applications for licenses are filed for projects which would develop, conserve, and utilize, in whole or in part, the same water resources, and one of the applications was filed by a permittee under an outstanding preliminary permit ("priority applicant"), then the Commission will select between or among the applicants on the following bases:

(1) The criteria of paragraph (f) of this section will govern selection among all applicants who are not priority applicants;

(2) If the plans of the priority applicant are at least as well adapted as the plans of each other applicant to develop, conserve, and utilize in the public interest the water resources of the region, taking into consideration the ability of each applicant to carry out its plans, then the Commission will favor the priority applicant; or

(3) If the plans of an applicant who is not a priority applicant are better adapted than the plans of the priority applicant to develop, conserve, and utilize in the public interest the water resources of the region, taking into consideration the ability of each applicant to carry out its plans, then the Commission will inform the priority applicant of the specific reasons why its plans are not as well adapted and afford a reasonable period of time for the priority applicant to render its plans at least as well adapted as the other plans. If the plans of the priority applicant are rendered at least as well adapted within the time allowed, then the Commission will favor the priority applicant. If the plans of the priority applicant are not rendered at least as well adapted within the time allowed, then the Commission will favor the other applicant.

§ 4.34 Hearings on applications.

The Commission may order a hearing on an application or applications for a preliminary permit or a license, upon either its own motion or the motion of any party in interest. Any such hearing shall be limited to the issues prescribed by order of the Commission.

§ 4.42 [Deleted]

§§ 4.41, 4.50, 4.51, 4.71 [Amended]

§ 16.6 [Amended]

§ 131.2 [Amended]

(B) Section 4.42 is deleted; all references to § 4.42 in §§ 4.41 and 4.51 are amended to refer to § 4.32; all references in §§ 4.50 and 4.71 to "§§ 4.40 to 4.42, inclusive" are amended to refer to "§§ 4.32, 4.40, and 4.41"; the reference in § 16.6 to "§§ 4.40 through 4.42 of this chapter, inclusive and in § 4.51 of this chapter" is amended to refer to "§§ 4.32, 4.40, 4.41, and 4.51 of this chapter"; and the reference in § 131.2 to "§§ 4.30–4.42 of this chapter" is amended to refer to "§§ 4.30–4.41 of this chapter."

(C) Sections 4.80 through 4.86 are amended by deleting the existing sections and replacing them with the following:

APPLICATION FOR PRELIMINARY PERMIT; AMENDMENT AND CANCELLATION OF PRELIMINARY PERMIT

§ 4.80 Applicability and purpose.

Sections 4.80 through 4.83 pertain to preliminary permits under Part I of the Federal Power Act. The sole purpose of a preliminary permit is to secure priority of application for a license for a water power project under Part I of the Federal Power Act while the permittee obtains the data and performs the acts required to determine the feasibility of the project and to support an application for a license.

§ 4.81 Contents of application.

Each application for a preliminary permit must include the following initial statement and numbered exhibits containing the information and documents specified:

(a) Initial statement:

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION APPLICATION FOR PRELIMINARY PERMIT

1. [Name of applicant] applies to the Federal Energy Regulatory Commission for a preliminary permit for the proposed [name of project] water power project, as described in the attached exhibits. This application is made in order that the applicant may secure and maintain priority of application for a license for the project under Part I of the Federal Power Act while obtaining the data and performing the acts required to determine the feasibility of the project and to support an application for a license.

2. The location of the proposed project is:

State or territory:————
County:————
Township or nearby town:————
Stream or other body of water:————

3. The exact name and business address of each applicant are:

———————————————

———————————————

———————————————

The exact name and business address of each person authorized to act as agent for the applicant in this application are:

———————————————

———————————————

———————————————

4. [Name of applicant] is a [citizen, association of citizens, domestic corporation, municipality, or state, as appropriate].

5. The proposed term of the requested permit is [period not to exceed 36 months].

(b) *Exhibit 1* must contain a description of the proposed project, specifying and including, to the extent possible:

(1) The number, physical composition, dimensions, general configuration and, where applicable, age and condition, of any dams, spillways, penstocks, powerhouses, tailraces, or other structures, whether existing or proposed, to be included as part of the project;

(2) The number, surface area, storage capacity, and normal maximum surface elevation (mean sea level) of any reservoirs, whether existing or proposed, to be included as part of the project;

(3) The number, length, voltage, interconnections and, where applicable, age and condition, of any primary transmission lines, whether existing or proposed, to be included as part of the project (see 16 U.S.C. 796(11));

(4) The number, rated capacity, total estimated average annual energy production and, where applicable, age and condition, of any turbines or generators, whether existing or proposed, to be included as part of the project;

(5) All lands of the United States that are enclosed within the proposed project boundary described under subparagraph (e)(3) of this section, identified and tabulated by legal subdivisions of a public land survey of the affected area; and

(6) Any other information demonstrating in what manner the proposed project would develop, conserve, and utilize in the public interest the water resources of the region.

(c) *Exhibit 2* must contain a study plan and work schedule, specifying and describing:

(1) Any studies, investigations, tests, or surveys that have already taken place, and any maps, plans, or specifications that have already been prepared, to determine the technical, economic, and financial feasibility of the proposed project (including any evaluation of its environmental impacts), or to support an application for a license for the project;

(2) Any studies, investigations, tests, or surveys that are proposed to be carried out, and any maps, plans, or specifications that are proposed to be prepared, to determine the technical, economic, and financial feasibility of the proposed project, taking into consideration its environmental impacts, and to support an application for a license for the project, including:

(i) A description, including the approximate location, of any activity that would alter or disturb lands or waters in the vicinity of the proposed project; and

(ii) An account of the applicant's plans to consult with federal, state, or local agencies, including those administering any public lands affected by the proposed project; and

(3) A proposed schedule, the total duration of which does not exceed the proposed term of the permit, showing:

(i) The intervals at which the studies, investigations, tests, surveys, maps, plans, or specifications identified

under subparagraph (2) are proposed to be completed;

(ii) The interval at which the applicant will determine finally that:

(A) The project is not technically, economically, or financially feasible, taking into consideration its environmental impacts, and an application for a license will not be filed; or

(B) The project is technically, economically, and financially feasible, taking into consideration its environmental impacts, and an application for a license will be filed; and

(iii) The interval at which the applicant will file an application for a license for the project, in the event the project is determined to be feasible.

(d) *Exhibit 3* must contain a statement of costs and financing, specifying and including, to the extent possible:

(1) The estimated costs of carrying out or preparing the studies, investigations, tests, surveys, maps, plans or specifications identified under paragraph (c)(2) of this section;

(2) The expected sources and extent of financing available to the applicant to carry out or prepare the studies, investigations, tests, surveys, maps, plans, or specifications identified under paragraph (c)(2) of this section; and

(3) A description of the proposed market for the power generated at the project, including the identity of the proposed purchaser or purchasers of the power, and any information that is available concerning the revenues to be derived from sale of the power.

(e) *Exhibit 4* must include a map or series of maps, to be prepared on United States Geological Survey topographical quadrangle sheets or similar planimetric maps of a state agency, if available. The map(s) need not conform to the precise specifications of paragraphs (a) and (b) of § 4.32. The map(s) must show:

(1) The location of the project as a whole with reference to the affected stream or other body of water and, if possible, to a nearby town or any other permanent monuments or objects that can be noted on the map and recognized in the field;

(2) The relative locations and physical interrelationships of the principal project features identified under paragraph (b) of this section; and

(3) A proposed boundary for the project, enclosing all of the principal project features identified under paragraph (b) of this section, any nonfederal lands necessary for the purposes of the project, and any lands of the United States (including reservations), identified on the map by legal subdivisions of a public land survey of the affected area (including the smallest of such subdivisions), that are occupied or used in whole or in part by the project. If the scale of the base map(s) is not sufficient to show clearly and legibly all of the information required by this paragraph, then the map(s) submitted must be enlarged to a scale that is adequate for that purpose.

§ 4.82 Amendments.

(a) Any permittee may file an application for amendment of its permit, including any extension of the term of the permit that would not cause the term to exceed three years. Each application for amendment of a permit must conform, as far as applicable, to the requirements of paragraphs (a) and (b) of § 4.31.

(b) If an application for amendment of a preliminary permit requests any material change in the proposed project, then public notice of the application will be issued as required in paragraph (c) (3) of § 4.31.

§ 4.83 Cancellation and loss of priority.

(a) The Commission may cancel a preliminary permit if the permittee fails to comply with the specific terms and conditions of the permit. The Commission may also cancel a permit for other good cause shown, after notice and opportunity for hearing. Cancellation of a permit will result in loss of the permittee's priority of application for a license for the proposed project.

(b) Failure of a permittee to file an application for a license before the permit expires will result in loss of the permittee's priority of application for a license for the proposed project.

§§ 131.3 and 131.4 [Amended]

(D) The reference in § 131.3 to "§§ 4.80–4.86 of this chapter" is deleted, and the reference in § 131.4 to "§§ 4.30–4.86 of this chapter" is amended to refer to "§§ 4.30–4.71 of this chapter."

§ 131.10 [Deleted]

(E) Section 131.10 is deleted in its entirety.

(F) The Secretary shall cause prompt publication of this notice to be made in the FEDERAL REGISTER.

¶ 32,010 Cost of Providing Retail Electric Service

44 F. R. 12438 (March 7, 1979)

[Docket No. RM 79-6]

COST OF PROVIDING RETAIL ELECTRIC SERVICE

Collection and Reporting of Information

MARCH 1, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Proposes regulations.

SUMMARY: These regulations implement section 133 of the Public Utility Regulatory Policies Act of 1978 and establish procedures governing the collection and reporting of information concerning the cost of providing retail electric service.

PUBLIC HEARINGS: Dates and locations to be announced.

WRITTEN COMMENTS: Written comments by April 6, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM 79-6)

FOR FURTHER INFORMATION CONTACT:

Gregory D. Martin, Office of Commissioner, Matthew Holden, 825 N. Capitol St., N.E., Room 9010, Washington, D.C. 20426, Phone: (202) 275-4176.

William Lindsay, Office of Electric Power Regulation, 825 N. Capitol St., N.E., Room 5200, Washington, D.C. 20426, Phone: (202) 275-4777

SUPPLEMENTARY INFORMATION:

BACKGROUND

We are issuing, at this time, *proposed* rules as to information that electric utilities shall report on the costs of providing electric service. These rules have been developed, to this point, under the instructions of Congress pursuant to section 133 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The law requires that the final rule be put into effect within 180 days of the date of enactment, that is, by May 8, 1979.

In view of the strict schedule set by the statute, the period for public comment on this proposed rulemaking is necessarily short. The *proposed* rule is not sacrosanct. We would welcome comments as to how it might be improved, so as to serve the purposes of the statute.

Insofar as the Commission is under a 6-month time constraint in issuing final rules with respect to this matter, we have attempted in the development of the proposed rule to provide for input by interested persons at the earliest possible stages in our development of this proposal. In particular, we have made a special effort to invite state regulatory authorities to communicate their views of how implementation of this rule will affect their responsibilities at the state level. We have also received a number of inquiries from national organizations concerned with electric utility regulation such as the American Public Power Association, the National Rural Electric Cooperatives, Inc., and the Edison Electric Institute. Commission staff was authorized to begin discussions with persons in these organizations as well as in other agencies of the government having regulatory and economic expertise. The records of these discussions have been made a part of the public file on this matter. We have directed that, in all such discussions and in following-up on any other inquires that have come to the attention of the Commission, the staff adhere scrupulously to the procedures for identifying and recording the subject matter of conversations in the manner earlier adhered to with respect to the development of the interim regulations under the Natural Gas Policy Act.

In addition, an informal public conference was held on December 4, 1978, the record of which was transcribed and analyzed for further use. This informal public conference, as well as the ongoing discussions we have held, have been of great value in establishing our understanding, to this point,

of the issues and the potential consequences perceived by persons who would be affected by the regulations which are now proposed.

These rules are now proposed for formal public consideration and the Commission will provide a full opportunity for oral as well as written comment. In order to assure the widest possible opportunity for comment, to take into account local and regional concerns, and to assist participants who may not be able to participate before the Commissionin Washington, D.C., the Commission will schedule several regional hearings on this proposed rulemaking.

TO WHOM WILL THE REGULATIONS APPLY AND WHAT INFORMATION IS TO BE SOUGHT?

The regulations will apply to all electric utilities having total sales, other than resale, in excess of 500 million kilowatt hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

The Secretary of Energy has identified electric utilities subject to these regulations. The first list issued for comment on December 22, 1978 (published here as Appendix A) contains: 157 investor-owned electric utilities; 29 cooperatively owned electric utilities; 69 non-Federal publicly owned electric utilities; and 3 Federally owned electric utilities.

Each utility with over this amount of retail sales is required to file with the Commission and its State regulatory authority all information except for information which may be proprietary concerning bills and consumption patterns of individual customers and information specifically exempted by the Commission. They are also required to make the information available to the public in the manner prescribed by the Commission. It should be noted regarding proprietary information that utilities will be required to make available for review by this Commission and the relevant State regulatory authority all information related to individual customers for verification and enforcement purposes.

Title I of PURPA states that the Congressional purposes are to encourage:

(1) the conversation of energy supplied by electric utilities;

(2) the optimization of the efficiency of use of facilities and resources; and

(3) equitable rates to electric consumers.

Congress required that State regulatory authorities and nonregulated utilities consider and make determinations regarding cost of service, the cost basis of declining block rates, time-of-day rates, seasonal rates, interruptible rates, and load management techniques within three years after the enactment of the Act or if that schedule is not met in the first rate proceeding which commences three years after the enactment of the Act. In addition, State regulatory authorities and nonregulated utilities are required under certain circumstances to make a determination as to whether or not lifeline rates should be implemented.

Congress expressly intended section 133 to be the vehicle for making good information regarding costs of providing electric service readily available to everyone concerned. ("Joint Explanatory Statement of the Committee of Conference," p. 86.)

At a minimum, the Commission is obligated under section 133 of PURPA to require the collection and reporting of information which allows, to the extent practicable, the identification of:

(1) customer, demand and energy costs components;

(2) costs of serving each customer class to include subgroups within classes, at different voltage levels, times of use and other appropriate factors;

(3) daily and seasonal kilowatt load curves for the utility system and each customer class served under different rate schedules;

(4) annual capital, maintenance and operating cost for transmitting and distributing electricity and for each generating unit; and

(5) costs of purchased power reflecting daily and seasonal differences.

Within the statute the Commission has broad discretion to require utilities to report cost of service information in the form and manner the Commission deems necessary to fulfill the purposes of section 133 of PURPA.

The Commission's authority to collect and publish information pursuant to other laws is not affected by any authority granted under PURPA.

WHAT INFORMATION IS NECESSARY?

In general, two costing methods, marginal costs and fully allocated costs and various applications of each, are employed by utilites and regulatory agencies. Both reflect the capital, operating and maintenance costs for generation, transmission, distribution and overhead. They attempt to measure those costs differently.

Fully allocated cost methods focus on total accounting costs incurred or expected to be incurred in the delivery of service during a specified period.

Marginal cost if defined as the expected change in the total cost of production to supply one additional unit of output.

We were faced, at the outset of this proceeding, with the question of whether we should require the reporting of information to express marginal costs exclusively, or information to express embedded costs exclusively.

We have considered both proposals. We have concluded at this time to propose the inclusion of both marginal and embedded costs.

Some have argued that section 115(a) calls for a marginalist method of determining costs, relying on the language concerning a change in total costs of additional capacity is added to meet additional demand. However, the "Joint Explanatory State of the Committee of Conference" specifically states:

> The Conferees chose the phrase "take into account" [the change in costs] so as not to imply a preference for a State regulatory authority or nonregulated utility to follow any specific costing methodology for determining cost of service. The State regulatory authority or nonregulated utility has discretion to select which costing methodology or methodologies it chooses, consistent with State law.

It is also clear the Congress contemplated broad opportunities for participation in rate proceedings. In this context it is the Commission's role to ensure, through the section 133 rule, that the states, utilities, consumers or intervenors all have good information on a timely basis. It would be inappropriate, on the basis of present knowledge, to attempt in this proposed rulemaking a definitive resolution of the major conceptual issues. The Commission should, instead, develop rules which can be used objectively to assist in a variety of cost determinations as may be indicated by the needs of users of the data. The accounting cost concepts are, in general, more clearly understood. On that basis, we here propose to require the reporting of both accounting and marginal costs.

The quantification of costs of service using the two methods involves the use of different procedures.

Fully allocated cost of service studies require the following information for the test year: rate base, depreciation, fixed operation and maintenance expenses, taxes and cost of capital. These items are functionalized under the generation, transmission and distribution functions. The analyst must also have, for the test year, information as to the utility's expenses for fuel, variable operation and maintenance expenses, power purchases, customer accounting, sales promotion, administration and other (general). Finally, the analyst needs some information about customer demands in the test year.

Collection of the accounting cost information (subpart B) coupled with the load information (subpart D), is intended to permit the development of fully allocated accounting cost of service studies under a variety of methods currently in use. The specification in this proposed rule of the various information elements should not be taken as a preference for any specific methodology which coincidentally is based on the same information elements.

The quantification of marginal costs is more complicated. At a minimum, it involves determining: (1) costing periods; (2) marginal energy (running) costs; (3) marginal generating capacity (demand) costs; (4) marginal transmission capacity costs; (5) marginal distribution costs (demand and customer costs); and (6) marginal losses.

In the electric utility industry, the change in output can be viewed as having three different dimensions: the additional cost of supplying an additional kilowatt-hour of electricity (marginal energy cost), the additional cost of supplying an additional kilowatt of capacity including the cost of

maintaining adequate reserve capacity (marginal capacity or demand cost), and the additional cost of adding a new customer (marginal customer cost). Marginal demand cost is measured per kilowatt (kW) of additional demand, energy cost per kilowatt-hour (kWh) of additional consumption, and customer cost per additional customer served.

The objective in determining costing periods is to differentiate between periods of high and low costs.

Marginal energy costs refer to the costs of fuel and variable operation and maintenance expenses incurred in producing an additional kilowatt of electricity.

Marginal generation capacity costs refer to the costs that would be incurred to meet a small permanent change in the level or pattern of demand.

Marginal transmission capacity costs reflect costs of additions to transmission systems that are causally related to system peak demand.

How marginal distribution costs should be determined is a matter on which there is no clear agreement among experts. The disagreement involves a proper distinction between customer-related distribution costs; *i.e.*, costs directly related to adding a new customer and varying proportionately to the number of customers, and demand related distribution costs; *i.e.*, costs associated with serving a particular load.

Another procedure in a marginal cost analysis is the computation of marginal losses. This procedure is necessary because losses affect marginal capacity and marginal energy costs. The size of the transmission and distribution facilities is related to the maximum load and energy losses during transmission and transformation. For purposes of most costing analyses, what needs to be determined is the difference between electricity input and electricity output; *i.e.*, and the difference between electricity generated and electricity delivered to customers at each voltage level.

Proponents of marginal costing do not agree on a single appropriate method. The diversity of professional opinion is also found within the Commission Staff. The Commission rejects, accordingly, the concept that it could or should approve any one model or set forth an authorized list of acceptable methods for calculating marginal costs under this regulation. However, we are proposing that each utility choose an appropriate marginal cost approach for calculating the costs of providing service.

The marginal cost information (subpart C), together with the load information (subpart D), should enable utilities (as well regulatory authorities and others) to calculate the extent to which total cost of supplying electric power is likely to change if, (1) additional capacity is added to meet peak demand; (2) additional kilowatt-hours of electric energy are delivered to customers; or (3) additional customers are added to the distribution system. In addition, the information will permit identification of differences in the cost of serving various classes of customers that can be attributed to receiving electricity at different voltage levels and to variations in daily and seasonal time of use.

RAW INFORMATION AND COST CALCULATION

The Commission has had to consider whether the purpose of section 133 whould best be served by requiring the utilities to report only single element information (hereafter referred to as raw information), which could then be used as the basis on which costs could be calculated by costing periods, by customer class and by voltage level, or whether utilities should report some level of calculated costs for such functions and classes. To be useful, the information must be calculated. The question is where the burden of the calculations should lie—with the utility providing the information or with each of the several potential users of the information, *i.e.*, state commissions, intervenors and the ERA.

The statutory language requires interpretation. In one part of section 133, there is reference ot information "necessary to allow determination of the costs associated with providing electric service;" in another part, the language seems to imply that costs should be calculated and reported by various categories.

In the informal comment period, there was substantial comment, espe-

cially form state agencies, in favor of a raw information approach. Certain state commissions have expressed the significantly different view that at least some level of calculation must be completed by the reporting utility in order to make the information useful to those who would seek to use it. Within the Commmission, most of the staff is convenced that the purposes of section 133 would best be served if utilities were required to report certain costs calculated by customer class, costing period, the voltage level.

While a raw information approach may be legally sufficient for purposes of carrying out the minimum requirements of section 133, for the purposes of this rulemaking we adopt the recommendations of the majority view among the staff, *viz.*, that the reporting utilities should be required to calculate marginal costs by customer class, by costing period and by voltage level.

With regard to the question of whether utilities should be required to report any cost calculations, whether marginal or accounting cost, as opposed to simply reporting raw information, at least one state commissioner and many of the FERC staff feel that it is necessary to require utilities to submit more material than that which would simply permit users other than the reporting utilities to calculate cost of service by class.

Attached to the proposed rule are two summary tables. Completion of one table would require the development of a full accounting cost study and completion of the other would require the performance of a marginal cost study, though in neither instance does the table require the use of a specific methodology. Comments are solicited specifically as to whether utilities should be required to calculate and report accounting and marginal costs using the summary tables as set out in the proposed rule.

If the Commission is not to require that reporting utilities calculate costs using the summary tables, the question becomes what is the irreducible minimum amount of information that must be reported by the subject utilities in order to reasonably permit the most likely potential users, or intervenors, to perform full marginal cost of service studies.

Comments are specifically asked to be directed at the following questions:

(1) With respect to marginal energy costs, whether the Commission should require utilities to report *calculated* marginal energy costs or whether it is reasonably possible for users of the reported raw information to derive marginal energy costs from the information as to the cost of fuel, power purchases, variable operations expenses and loads, as required in the proposed regulation; and

(2) Whether the utilities should be required to *calculate* a carrying charge rate or whether raw information as to income and property taxes, depreciation, return and expenses are sufficient so as to allow the user to reasonably perform such a calculation.

To assist the public in its consideration, Appendix B contains the staff's concept of the basis for the margin cost information call proposed in the rulemaking and Appendix C contains the concept as proposed for the raw information approach. The proposed rulemeking assumes that the utilities are uniquely situated to calculate the margin energy costs and a carrying charge rate. Appendix C reflects the determination that parties other than the utilities can calculate those items given certain raw information.

FORMAT FOR COLLECTION OF RAW INFORMATION

Regarding the appropriate format for the collection of raw information, the question to which comments are specifically solicited, is whether the raw information tools now available to us (FERC Form 1 already required by 18 CFR 141.1 of a majority of the utilities subject to this rulemaking) can be modified to allow us as a practical matter to meet the purposes of the law. The most likely alternative to the modifying of Form 1 would be the development of an entirely new form.

We have considered, but not here proposed, an approach which would utilize an existing report, FERC Form 1, required by 18 CFR 141.1. Much of the information required for either generic approach (marginal or fully allocated) may well be already contained in FERC Form 1 with the exception of some information as to future plant, costs and loads. Since most privately-owned utilities covered by Title I of

PURPA must file the FERC Form 1 annually, this approach would utilize the form, with certain amendments, for section 133 purposes. It would also be necessary to expand the form so as to include those entities that do not now report in that fashion.

Under the Form 1 raw information proposal, utilities covered under section 133 would be required to file information, including load information, annually. Both the proposed rule and the Form 1 raw information proposal would require utilities to conduct load research at least every five years.

Filing requirements under the Form 1 raw information proposal would apply to each utility with annual electric operating revenues of $2,500,000 or more whether or not the utility is jurisdictional under the Federal Power Act and each electric utility covered by section 133. Electric utilities which do not meet the 500 million kilowatt hours sales other than resale standard would be exempt from the requirement to report class load information and cost information relating to planned additions to plant.

They would also be exempt from filing the several years of historic information relating to plant, sales, operations and loads. Under this alternate approach, the initial filing date would be extended to March 31, 1981, four months beyond that prescribed in section 133(c).

For a more thorough treatment of the Form 1 approach, see Appendix C.

WHAT LOAD INFORMATION IS NECESSARY?

Section 133(a)(2) of PURPA requires the gathering of information with respect to customers' demand for electricity reflecting daily and seasonal differences in use. The proposed regulation would require the collection of this load information for individual customer classes, the system as a whole, and in certain cases, for power pools. The proposed regulation would also require the reporting of certain system, pool and class loads that may be needed for estimation of marginal costs and accounting costs.

The majority of the load information is required for the reporting period, but there are additional requirements for systems (or pool) load reporting for historic and projected periods. For individual class load information collection, an accuracy standard is established consistent with general industry practice in conducting load research.

The Commission recognizes that large expenses may be associated with conducting load research. We also understand that, in most instances, class load shapes do not change appreciably over the short run. For those reasons, the regulations require updated load research no more frequently than every five years. The class load information to be reported, however, is that applicable to the current period. Load research conducted within five years of the reporting period can provide estimates of class load factors, from which estimates of current class loads can be obtained when combined with current kWh sales, numbers of customers and other factors such as known changes in appliance mix.

Without detailing the specific information required, there are several aspects of this section of the proposed regulation to which we call special attention. Specifically, there are five blanket exemptions that are proposed in this rulemaking to be granted in the final rule. One exemption is for the *separate* reporting of all load data for a class if it represents no more than 5% of the annual or daily system peak and is not a major retail class (*i.e.*, residential, commercial, industrial). Instead, that class may be combined with other classes for reporting purposes. The second exemption would be to the reporting of *hourly* class load data by utilities for any small class meeting the criteria of the first exemption. The third proposed exemption would release the reporting utility from the accuracy standard for sampling of loads, if loads can be estimated without sampling, such as for street lighting, or if load data from other utilities are to be used. The transferability of the load data must be documented as a condition of the exemption. The fourth blanket exemption would apply if the State regulatory authority waived the requirement for *separate* jurisdictional reporting of class loads. Finally, for any utility given an extension for filing class load data, an exemption would be granted to filing load data at the time of a request for a rate increase.

Two exemptions would be considered and would require a separate application under the "Exemption and Extension" section of the proposed rules. One exemption would be considered for filing load data for any customer class if this class is to be drastically altered or eliminated. An exemption also would be considered for utilities reporting separately the class load data if they intend to jointly engage in load research.

One blanket extension is proposed to be granted in the final rule. For any utility that has not commenced load research on the date of the PURPA enactment, or that has not been directed to do so by its State regulatory agency, a one-year extension for filing *hourly* class load data would be allowed.

EXEMPTIONS AND EXTENSIONS

Section 133 provides that these rules:

> . . . may provide for the exemption by the Commission of an electric utility or class of electric utilities from gathering all or part of such information, in cases where such utility or utilities show and the Commission finds after public notice and opportunity for the presentation of written data, views, and arguments that gathering such information is not likely to carry out the purposes of this section.

The proposed rules establish a mechanism for the application for an granting of such exemptions in the future. In addition, the proposed rules would immediately grant certain exemptions, based upon showings to be made by utilities during the process of this rulemaking. As to these proposed exemptions, this proposed rulemaking constitutes the public notice, and the opportunity for comment on the proposed rules constitutes the comment opportunity required by section 133 before an exemption may be granted, as it would be in this instance in the final rule. In accordance with the terms of the Act, utilities or classes of utilities desiring these proposed exemptions must show in their comments on this proposed rule that the gathering of the information covered by the exemption is not likely to carry out the purposes of section 133.

The proposed general procedure for the granting of exemptions is found in subpart F. The particular exemptions which would be granted in this rule all have to do with load information (subpart D), and are described above in the section of the Preamble dealing with load information.

Finally, section 133 provides particularly that the Commission may permit an extension of the first reporting obligation, otherwise occurring two years after enactment, "for good cause shown." It is noteworthy that both the criterion and procedure for the granting of such extensions are less rigorous than those established for exemptions. As with the exemptions, the proposed rules both establish a mechanism for granting extensions (in subpart F) and propose a particular extension (in subpart D) of one year for the filing of hourly class load data for utilities which have not commenced a class load research program as of the date of enactment.

WRITTEN COMMENTS

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Comments should reference Docket No. RM79-6 on the outside of the envelope and on all documents submitted to the Commission. In view of the short comment period available on these proposed regulations, and in order that the Commission be able to take into account as many comments as possible, the Commission requests that persons submitting comments assist in three ways. First, persons should identify specifically the section or subpart they are addressing. Second, comments should clearly state whether they involve technical, policy or legal matters. Finally, where comments urge a different approach from one presented, specific alternative language should be proposed to the extent practicable.

Fifteen (15) copies should be submitted. All comments and related infor-

mation received by the Commission by April 6, 1979 will be considered prior to the promulgation of interim regulations on May 8, 1979. All comments will be retained and considered prior to the promulgation of final regulations.

The Commission intends to allow an opportunity for the oral presentation of data, views and arguments. These proceedings will be held at times and places to be announced.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267).

In consideration of the foregoing, it is proposed to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

KENNETH F. PLUMB,
Secretary.

1. Chapter I of Title 18 is amended by adding new Subchapter K, Part 290 to read as follows:

SUBCHAPTER K—REGULATIONS UNDER THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

PART 290—COLLECTION OF COST OF SERVICE INFORMATION UNDER SECTION 133 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

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AUTHORITY: This part is issued under the Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3117.

Subpart A—Coverage, Compliance and Form of the Information

§ 290.101 Coverage.

These rules apply to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before

the immediately preceding calendar year.

§ 290.102 Compliance.

(a) *Information gathering and filing.* Each electric utility covered under these rules shall gather information as specified in Subparts B, C, D, and E of this part, and shall file an original and one copy of such information with the Federal Energy Regulatory Commission (Commission) and an additional copy of such information with each State regulatory authority having ratemaking authority over such utility. The utility shall retain additional copies of such information and shall make them available at the principal offices of the utility for public inspection and copying.

(b) *Time of filing and reporting period.* (1) Information required under paragraph (a) of this section shall be filed on or before November 1, 1980, and on or before the date 2 years after the date of the initial filing, except as provided in paragraph (c) of this section.

(2) Except as specified in paragraph (c)(2) of this section, the reporting period covered by the information shall be a recent 12-month period the end date of which does not precede the filing date by more than 6 months. Information for earlier years and future years, as specified in Subparts C and D of this part, shall be reported on a calendar year basis.

(c) *Reporting of information at the time of a rate increase application.* (1) At the time of making an application or proposal for a rate increase, each utility shall file with the Commission and appropriate State ratemaking authorities, and make available to the public, the information specified in Subparts B, C, D, and E of this part. The utility shall next be required to file information specified in Subparts B, C, D, and E of this part 2 years from the time of the rate increase application, or at the time of the next subsequent rate increase application, whichever occurs first.

(2) The reporting period covered by the information required under paragraph (c)(1) of this section shall be the same as the test period that is used in the calculations supporting the rate increase application. If a future test period is used, the information shall be estimated for the test period, and the procedure used for estimation shall be described. Information for earlier years and future years, as required in Subparts C and D of this part, shall be reported on a calendar year basis.

(d) *Date of initial filing.* The provisions of paragraph (c) of this section do not take effect prior to November 1, 1980.

§ 290.103 Form of the information.

The information required to be reported shall be submitted on suitable standard forms prescribed by the Commission or in any form otherwise determined by the Commission. With regard to specific items of cost information, if an account number from the FERC Uniform System of Accounts is specified in Subparts B and C, public utilities under the Federal Power Act shall file in accordance with the specified accounts. Utilities covered by Section 133 of the Public Utility Regulatory Policies Act (PURPA) but not presently required to keep their books by the FERC Uniform System of Accounts may provide this information in accordance with the system of accounts presently employed, so long as all required individual items of information are fully defined and expressed in the same detail as in the FERC Uniform System of Accounts.

Subpart B—Accounting Cost Information

§ 290.201 Rate base information.

For rate base information, balances shall be reported at the beginning and end of the reporting period together with the average of the thirteen monthly balances, if available. The following information shall be reported:

(a) *Plant accounts.* For plant account balances, (FERC [1] Accounts 301 through 399) and any sub-accounts:

(1) The balances in each account, by account.

(2) A functional breakdown of distribution plant into demand and custom-

[1] FERC accounts refer to FPC accounts so numbered.

er related components, and an explanation of the functional allocation used.

(3) A breakdown of demand related transmission or distribution plant assigned to the different service levels provided and an explanation of this allocation.

(4) A breakdown of all plant directly assigned to specific customers or customer classes if such assignment is appropriate based on prior precedent.

(b) *Depreciation reserve.* The depreciation reserve associated with each plant account specified in paragraph (a) of this section, by account number.

(c) *Depreciation expense.* The depreciation expense associated with each plant account specified in paragraph (a) of this section, by account number.

(d) *Cash working capital.* Estimates of cash working capital required, including an explanation of the computation. Sufficient information shall be submitted to enable a calculation on the basis of the conventions utilized in the particular jurisdictions. If the estimated cash working capital requirement is based on a lead lag study, a summary of the study shall also be filed.

(e) *Construction work in progress.* For each project under construction:

(1) A description of plant including appropriate functionalization; such as production, transmission, distribution, general, common, and other.

(2) A starting construction date.

(3) The expected completion date and estimated cost as of the in-service date.

(f) *Prepayments.* A breakdown of the components of all prepayments.

(g) *Accumulated deferred income tax.* The amount of accumulated deferred income taxes, with an explanation as to their derivation and source.

(h) *Materials and supplies.* The amounts for materials and supplies (FERC Accounts 151 through 163).

(i) *Electric plant held for future use.* The amount for electric plant held for future use, itemized as to land and other, and functionalized.

(j) *Nuclear fuel materials.* The amounts for nuclear fuel materials (FERC accounts 120.1 through 120.3).

§ 290.202 Operation and maintenance cost information.

For O&M expenses the following information shall be reported:

(a) *Operation & Maintenance expense accounts.* For O&M expenses (FERC accounts 500 through 598 and 901 through 932) and any subaccounts:

(1) The balances in each account, by account.

(2) A functional breakdown of distribution O&M expenses into demand and customer related components and an explanation of the functional allocation made.

(3) A breakdown of demand related transmission and distribution O&M expenses assigned to the different service levels provided and an explanation of the allocation method.

(4) A breakdown of all O&M expenses directly assigned to specific customers or customer classes if such assignment is appropriate based on prior precedent.

(5) Monthly information on fuel expense, estimating the amounts for each month included in each of the costing periods utilized in reporting the marginal costing information under Subpart C of this part.

(b) *Payroll.* The payroll associate with each O&M expense account, by account number.

(c) *Taxes.* All property taxes, payments in lieu of taxes, and other non-income-related taxes.

§ 290.203 Income and sales tax information.

If applicable to the reporting period, the following information necessary to calculate income and sales tax shall be reported:

(a) *Tax rates.* The applicable income tax rates and sales tax rates.

(b) *Differences in income items and deductions.* A specification of the differences in income items and deductions for Federal and State income taxes.

(c) *Itemized deductions.* An itemization of the Federal income tax deductions in addition to those contained in §§ 290.201 and 290.202; such as, interest, tax depreciation above book depreciation, etc.

(d) *Adjustments to taxes.* Federal and State adjustments for such items as provisions for deferred income

taxes, income taxes deferred in previous years, and investment tax credits, including the amortization and reporting period amounts.

§ 290.204 Rate of return information.

The following information shall be averaged for the reporting period and reported:

(a) *Capitalization.*

(b) *Costs of capital.* Costs of capital, including interest costs and book values of the various issues of debt and preferred stock book value and dividends for the various issues of preferred stock.

Subpart C—Marginal Cost Information

§ 290.301 General instructions for reporting marginal cost information.

All marginal cost information shall be reported in accordance with the following general instructions:

(a) *Estimates of future costs and inflation factors used.* All estimates of future costs shall be reported in constant (base year) dollars, and the inflation factors used shall be indicated.

(b) *Historic costs.* All historic costs shall be as recorded.

(c) *Designation of estimations.* All estimated historic and reporting year information shall be designated "Est,".

(d) *Information not applicable.* All requested information not applicable to the utility's operations shall be designated "Not Applicable".

§ 290.302 Generation cost information.

For generation costs the following information shall be reported:

(a) *Production planning information for existing generating plants.* For each generating unit within an existing generating plant:

(1) Plant-unit identification.

(2) If jointly owned, the percent ownership of the unit's total capability.

(3) The kind of unit (steam, internal combustion, gas turbine, nuclear, conventional hydroelectric, pumped storage, or other);

(4) Estimated retirement date.

(5) Primary and secondary fuel types.

(6) Maximum generator nameplate rating (in kilowatts) and reratings, if any.

(7) Net continuous unit capability (in kilowatts):

(i) When not limited by condenser water; and

(ii) When limited by condenser water.

(8) Normalized annual fixed operation and maintenance expenses.

(9) Cost of fuel per kilowatt-hour of net generation under typical operating conditions.

(10) Cost of fuel per million Btu's.

(11) Heat rates at 100, 75 and 50 percent of rated capacity.

(12) Non-fuel variable operating costs per kilowatt-hour of net generation for the reporting year and, if expected to change, for each of the next 10 years.

(13) Maintenance requirements (days of maintenance per year) for the reporting year and, if expected to change, for each of the next 10 years.

(14) Forced outage rates (percent) for the reporting year and, if expected to change, for each of the next 10 years.

(15) Minimum daily operating capacity.

(16) Start-up time to achieve 85 percent of nameplate capacity.

(17) If the unit is hydroelectric, the following information for each month of the reporting year and, if expected to change, for each month of the next 10 years:

(i) Kilowatt-hour production.

(ii) Maximum continuous generating capability.

(b) *Production planning information for planned additions to generating plants.* For each generating unit which is planned to go into operation during the next 10 years:

(1) Plant-unit identification.

(2) If to be jointly owned, the planned percent ownership of the unit's planned capability.

(3) Kind of unit (steam, internal combustion, gas turbine, nuclear, conventional hydroelectric, pumped storage, or other).

(4) Planned date of commercial operation.

(5) Estimated earliest possible date of commercial operation.

(6) Estimated plant life.

(7) Primary and secondary fuel types.

(8) Maximum generator nameplate rating (kilowatts).

(9) Annual estimated expenditures up to planned date of commercial operation (including AFUDC or CWIP earnings as applicable).

(10) Estimated capital cost per kilowatt.

(11) Estimated annual fixed operation and maintenance expenses.

(12) Estimated cost of fuel per kilowatt-hour of net generation.

(13) Estimated cost of fuel per million Btu's.

(14) Estimated heat rates at 100, 75 and 50 percent of rated capacity.

(15) Estimated non-fuel variable operating costs per kilowatt-hour of net generation.

(16) Estimated maintenance requirements (days of maintenance per year) for the first year of commercial operation and, if expected to change, for each of the remaining years in the 10-year planning period.

(17) Estimated forced outage rates (percent) for the first year of commercial operation and, if expected to change, for each of the remaining years in the 10-year planning period.

(18) If the unit is hydroelectric, the following information for each month of the first year of commercial operation and, if expected to change, for each month of the remaining years in the 10-year planning period:

(i) Kilowatt-hour production.

(ii) Maximum continous generating capability.

(c) *Planning method used.* A description of the system planning method or model used to determine the pattern of generating capacity additions specified in paragraph (b) of this section.

(d) *Ten year resource forecast requirements.* A 10-year resource plan which identifies the requirements for the construction of new electric generating facilities to meet forecasted system summer and winter peak load levels, as indicated in the demand forecast specified in § 290.402(e); for the summer and winter peaks of each of the 10 years in the planning period, the following information:

(1) The net dependable capacity available from existing generating plants.

(2) The total capacity available from firm purchases.

(3) The total firm capacity obligations to other systems.

(4) The net dependable capacity plus net purchases (paragraphs (d)(1) plus (d)(2) of this section minus paragraph (d)(3)).

(5) The total reserve capacity required for the system.

(6) The reserve capacity available through interchange or emergency agreements.

(7) The reserve capacity required to be supplied by own system (paragraph (d)(5) of this section minus paragraph (d)(6)).

(8) The net assured system capacity (paragraph (d)(4) of this section minus paragraph (d)(5)).

(e) *Estimated capital investment and operation and maintenance expense.* (1) The estimated capital investment (per kilowatt of installed capacity) if a hypothetical minimum cost (per kilowatt) generating unit of an appropriate size were installed.

(2) The estimated fuel and variable O&M expenses (per kilowatt-hour) for this unit.

§ 290.303 Energy cost information.

For energy costs the following information shall be reported:

(a) *Hourly marginal energy costs.* Hourly marginal energy costs (cents per kWh) for the reporting year and for the next 5 years.

(b) *Typical hourly marginal energy costs as an alternative.* As an alternative to paragraph (a) of this section, hourly marginal energy costs for a typical weekday, a typical weekend day and the system's peak day for each month of the reporting year and the next 5 years, if the utility certifies that it will make the information specified in paragraph (a) of this section available upon request.

(c) *Pool hourly marginal energy costs.* As an alternative to paragraphs (a) and (b) of this section, the hourly marginal energy costs for the pool if the utility is a member of a centrally dispatched power pool.

(d) *Procedures used.* A general description of the procedures used in estimating hourly marginal energy costs.

(e) *Hydroelectric units.* If a hydroelectric unit is used to meet a marginal load, the assumptions and procedures used in valuing the electricity produced from the hydro source.

(f) *Effect of purchased power costs.* The hours in which the marginal energy cost is likely to be determined by the price paid for purchased power, with citations to contracts, tariffs or agreements currently in effect and likely to determine the hourly marginal energy costs indicated in paragraphs (a), (b) or (c).

(g) *Marginal energy costs by costing period and by year.* Estimates of the average hourly marginal energy cost by costing period for the reporting year and for the next 5 years using the costing periods specified in § 290.308.

(h) *Calculated marginal energy costs by costing period.* A single marginal energy cost calculated for each of the costing periods, using the information specified in paragraph (g) of this section and the assumptions and procedures used in making these calculations.

(i) *Effect of energy loss.* The estimated marginal energy costs at the principal delivery voltage levels for the different costing periods using the estimates of energy loss factors specified in § 290.406(c).

§ 290.304 Transmission cost information.

For transmission costs the following information shall be reported:

(a) *Plant information.* For transmission plant:

(1) The cost of additions to transmission plant, excluding replacements, by voltage level for the reporting year and for each of the previous 10 years, including all capitalized costs (for example, AFUDC).

(2) The annual budgeted costs of additions to transmission plant, excluding replacements, by voltage level for each of the next 10 years, including all capitalized costs (for example, AFUDC).

(3) An estimate of the costs of additional transmission plant that would be required for the installation of the hypothetical minimum cost per kilowatt generating unit described in § 290.302(e).

(4) For paragraphs (a)(1) and (a)(2) of this section, payments received or an estimate of those to be received from other utilities for use of the additional transmission capacity.

(5) A system map showing existing generation sites and transmission lines and those proposed for the next 10 years.

(b) *Operation and maintenance expense.* For O&M expenses (FERC Accounts 560 through 573):

(1) The transmission O&M expenses for the reporting year and for each of the previous 10 years, adjusting any extraordinary or non-recurring expenses to typical levels.

(2) The estimated transmission O&M expenses for each of the next 10 years.

(3) The O&M expenses associated with the installation of the transmission plant specified in paragraph (a)(3) of this section.

(4) For paragraphs (b)(1) and (b)(2) of this section, the following:

(i) Dispatch expenses related to pool or interchange operations.

(ii) Any fixed payments, such as rental payments.

§ 290.305 Distribution and customer cost information.

For distribution and customer costs the following information shall be reported:

(a) *Plant information.* For distribution plant:

(1) The account balances (FERC Accounts 360 through 373) for each of the previous 5 years and for each of the next 5 years.

(2) For paragraph (a)(1) of this section, the amount of investment incurred each year for replacement of existing plant.

(3) For the reporting year, an estimate of the investment associated with a minimum distribution system; that is, the investment in facilities at capacity levels sufficient to serve customers at a minimum level of demand. (The minimum level of demand is the actual minimum demand level for which service is currently being installed. A methodology for determining a minimum distribution system is described in Chapter VI of the *Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Utility Commissioners (1973, Washington, D.C.).)

(4) As an alternative to paragraph (a)(3) of this section, a certification by the utility that it will make the information specified in paragraph (a)(3) available upon request.

(5) An estimate of the current cost of connecting a new customer to the distribution system for each customer class.

(b) *Operation and maintenance expense.* For O&M expenses:

(1) The account balances (FERC Accounts 580 through 598) for each of the previous 5 years and for each of the next 5 years.

(2) For paragraph (b)(1) of this section, a breakdown of:

(i) All O&M expenses directly assigned to specific customers or customer classes.

(ii) Extraordinary and non-recurring expenses.

(3) For each item in paragraph (b)(2) of this section, a differentiation between costs associated with materials and costs associated with labor.

§ 290.306 Other cost information to be reported.

For each of the previous 5 years, the following information shall be reported:

(a) *Customer expenses.* Customer account expenses, by account (FERC Accounts 901 through 910).

(b) *Sales expenses.* Sales expenses, by account (FERC Accounts 911 through 916), indicating separate amounts attributable to specific customers or customer classes.

(c) *Administrative and general expenses.* Administrative and general expenses, by account (FERC Accounts 920 through 932).

(d) *Certain taxes.* Social security and unemployment taxes paid (FERC Account 480.1).

(e) *Electric plant in service.* Electric plant in service, end of the year (FERC Account 101).

(f) *General plant.* General plant, by account, end of the year (FERC Accounts 389 through 399).

(g) *Materials and supplies.* Materials and supplies, by account, end of the year (FERC Accounts 151 through 157 and 163).

(h) *Prepayments.* Prepayments, end of the year (FERC Account 165).

§ 290.307 Annual carrying charge rates.

For annual carrying charge rates the following shall be reported:

(a) *Estimates.* Estimates of current annual carrying charge rates for generation, transmission, and distribution facilities based on annual revenue requirement calculations for hypothetical $1000 investments and calculated in accordance with the following rules:

(1) Carrying charge rates shall reflect only 4 types of cost—depreciation, return, income and property related taxes, and insurance.

(2) The calculations shall correspond to the regulatory prescriptions of the predominant regulatory authority. If the reporting utility operates in more than one state and if differences in regulatory prescriptions between states significantly affect the carrying charges rates (and, thus, system planning), such differences shall be indicated by the presentation of separate carrying charge rates for each jurisdiction.

(3) Publicly owned systems shall present carrying charge rates calculated with reference to the cost factors relevant to their system planning.

(4) The rate of return component shall be based on the utility's expected capital structure and marginal costs of debt, preferred, and common equity or customer contributed capital. The utility may use the allowed rate of return on common equity from its last rate proceeding as the component cost of common equity.

(b) *Worksheets.* Worksheets showing how the calculations specified in paragraph (a) of this section were made and indicating the basis for each cost component.

§ 290.308 Costing periods.

The costing periods that could be used to implement time differentiated pricing shall be reported as well as a description of the information and assumptions used in deriving these costing periods.

Subpart D—Load Information

§ 290.401 General instructions for reporting load information.

Load information shall be reported in accordance with the following general instructions:

(a) *Hourly load information.* Kilowatt (kW) loads shall be reported as total 60-minute integrated demands for each hour of a 24-hour period, beginning at 12:01 a.m. and ending at 12:00 midnight, local time. If loads are

metered on a different basis, the time interval of integration and the factor which converts reported loads to an hourly intergrated basis shall be specified.

(b) *Separate jurisdictional loads.* For utilities that serve at retail in more than one retail regulatory jurisdiction, individual customer class loads, as specified in § 290.403, shall be reported separately for each jurisdiction.

(c) *Master metering.* For purposes of reporting information in § 290.406, "customers" shall be defined as meters. A utility which uses master metering shall report the number of master meters separately and identify the classes of customers served under master meters.

(d) *Typical day loads.* For typical day loads, as specified in §§ 290.402 and 290.403, the kW loads reported for each hour shall be the average of the hourly loads for the given hour for each weekday or weekend day in each month.

§ 290.402 Load information for the total of all customer classes (system load information).

For system load the following information shall be reported:

(a) *General.* The kW load as measured by the sum of the coincidental net generation and purchases, plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system, which information shall be consistent with the monthly coincidental peak kW loads as reported in FERC Form 1, *Annual Report*, p. 431, column (b).

(b) *Pool load information.* If the utility is a member of a power pool that centrally dispatches or a power pool that plans future bulk power facilities as a pool, load information, as specified in this section, for the pool as well as the utility, unless otherwise indicated. If one member of the pool satisfies this filing requirement, the other members need only name the utility reporting the information.

(c) *Historic peak loads.* For each of the previous 10 years, the annual peak load (kWs) on the system, indicating the date, day of the week and time of day for each peak. This information is not required for power pool reporting.

(d) *Reporting period loads.* For the reporting period:

(1) kW load for each clock hour of each day. Utilities that provide the Edison Electric Institute with "Load Diversity Studies" may provide this information in computer compatible form to satisfy this reporting requirement.

(2) As an alternative to paragraph (d)(1) of this section, hourly system loads for a typical weekday, a typical weekend day and the system's peak day for each month in the reporting period, if the utility certifies that it will make the information specified in paragraph (d)(1) of this section available upon request.

(3) Actual and weather normalized monthly peak (maximum coincidental kW) load for each month, indicating the date, day of the week and time of day for each peak.

(4) Actual and weather normalized summer and winter peak (maximum coincidental kW) load.

(5) Maximum demand (kWs) on the distribution system at the primary and secondary voltage levels, and identification of the primary and secondary distribution voltages (kVs). This information is not required for power pool reporting.

(e) *Projected load information.* For each of the next 10 years:

(1) The projected annual load duration curves and the duration of load (in hours) at 100, 80, 60, 40, and 20 percent of the peak load and an indication as to whether this information was used as the basis for the planned capacity additions reported under § 290.302(b).

(2) The average annual growth rates implied by the projected load curves specified in paragraph (e)(1), for total kilowatt-hour sales, summer peak load, and winter peak load.

(3) Hourly loads for a typical weekday, a typical weekend day and the system's peak day for each month.

(4) The projected maximum demand (kWs) on the distribution system at the primary and secondary voltage levels, using the same definition of primary and secondary distribution as used in reporting under paragraph (d)(5) of this section.

§ 290.403 Load information for individual customer classes.

(a) *General.* For each customer class for which there is a separate rate and for each month in the reporting period, the following information shall be reported:

(1) The class maximum demand, in kWs, noncoincidental with the system peak.

(2) The class contribution in kWs, to the monthly maximum jurisdictional noncoincidental (with the system) demand.

(3) The class contribution, in KWs, to the monthly system maximum coincidental demand.

(4) Hourly class loads for a typical weekday, a typical weekend day, the class's peak day, the jurisdiction's peak day and the system's peak day.

(b) *Use of estimated information.* Information specified in paragraph (a) of this section may be obtained for each customer class through the use of estimation techniques.

(1) Estimates may be based on sample metering, except where load estimates of comparable accuracy can otherwise be made.

(2) Sampling techniques based on metering of groups of customers shall be acceptable if adequate account is taken of demand diversity and if the required statistical accuracy criteria specified in paragraph (c) of this section are satisfied.

(3) A description of the sampling method used shall be provided by the utility.

(c) *Accuracy standard.* The sampling method and procedures for collecting, processing, and analyzing the sample loads, taken together, shall be adequate to ensure that each mean hourly load reported for the class represents the actual class load to an accuracy of ± 10 percent at the 95 percent confidence level.

(d) *Load research conducted every 5 years.* The load research necessary for reporting class loads specified in paragraph (a) of this section need not be conducted more frequently than every 5 years. For each reporting period, the class load factors (hourly, daily and monthly) derived from the most recent load research study shall be used to estimate the kW demand using current kWh sales, customers and other billing determinants. A description and example of the estimation technique and underlying information used for the estimation shall be provided.

§ 290.404 Certain exemptions from reporting load information by individual customer classes.

(a) *Combined reporting of class load information.* For reporting class loads specified in § 290.403(a), 2 customer classes may be combined for any reporting period so long as at least one of the classes does not have loads of 5 percent or more of either the system's daily or annual peak loads and so long as they are not both major customer classes (residential, commercial, industrial). A combined class may be further combined with other customer classes if the criteria specified in this paragraph are met.

(b) *Exemption for hourly load information.* A utility is exempted from reporting hourly class load information as specified in § 290.403(a) for each reporting period if, for the customer class, the class loads (or the combined class loads if the classes have been combined pursuant to paragraph (a) of this section) are not 5 percent or more of either the system's daily or annual peak load, so long as the class (or any part of the combined class) is not a major customer class as defined in paragraph (a) of this section.

(c) *Provisions for exemption from accuracy standard.* Class load information need not meet the accuracy standards specified in § 290.403(c), if:

(1) The customer class laods for a particular class may be determined from methods not dependent on direct measurement or sampling; or

(2) The customer class loads for a similarly situated utility are to be used instead.

(d) *Support for borrowed information.* For customer classes exempted from the accuracy standard under paragraph (c)(2) of this section, applicable material supporting the adequacy of the borrowed load information shall be submitted for the customer classes for which the exemption is taken. The material shall include such information as climate variation, type of commercial or industrial activity, residential construction types, customer mix, large appliance saturation, and

other geographic, economic and demographic information as may properly support a claim of comparability.

(e) *Applicability of borrowed information.* For customer classes exempted from the accuracy standards under paragraph (c)(2) of this section, suitable adjustments for numbers of customers and total consumption shall be made to ensure the applicability of load information to the exempted class.

(f) *Waiver of reporting requirement for retail jurisdictional loads.* Class loads need not be reported separately by retail jurisdiction if the regulatory bodies in the 2 or more jurisdictions agree to waive the requirement for separate jurisdictional reporting.

(g) *Exemption based on extension of time.* Any utility granted a 1-year extension for filing hourly class load information under § 290.405(a) is also exempted from filing such information if the utility applies for a rate increase during the 1-year extension period.

(h) *No exemptions for major classes on time of use rates.* No exemption will be granted for information specified in paragraphs (a) through (g) of this section regarding a customer class, if the class is a subclass of one of the major retail customer classes and is served under a separate rate schedule based on time of use.

(i) *Exemption if the customer class is to be changed.* An exemption may be granted from the reporting requirements of this section if a utility serves a customer class under a separate rate schedule and that class is to be combined with another class of customers or is to be drastically altered, either on the initiative of the utility or at the direction of the State regulatory agency. The utility shall apply for such exemption under § 290.601.

(j) *Exemption for joint load research.* If a group of utilities intends to engage in joint load research for the purpose of fulfilling the reporting requirements of §§ 290.402 and 290.403, the group may apply to the Commission under § 290.601 for an exemption from the requirement that each utility in the group separately report system and class load information.

§ 290.405 Extension for reporting hourly load information by individual customer classes.

Any utility which certifies that it had not commenced a program for the collection of hourly class load information by means of sample metering or other techniques at the time that PURPA was passed and had not been ordered to collect such information by any other regulatory authority, shall be granted a 1-year extension beyond the initial 2-year filing period for reporting the hourly class load information specified in § 290.403(a)(4).

§ 290.406 Other information to be reported.

The following additional information shall be reported:

(a) *Assumptions used and description of weather normalization techniques.* For weather normalized information reported in § 290.402 and for any other load information normalized for weather, the utility shall report the weather parameters used for normalization and a brief description and demonstration of the normalization techniques employed.

(b) *Information on individual customer classes.* For each individual customer class included in § 290.403(a) the following information shall be reported:

(1) The monthly energy sales, in thousand kWh, for each month in the reporting period.

(2) The number of customers at the end of the reporting period.

(3) For the reporting period and for each of the previous 5 years, the number of new customers by primary, secondary, and transmission voltage levels, including an identification of the voltage (kVs) included in the primary, secondary, and transmission voltage levels.

(c) *Loss factors.* The utility shall report the estimated loss factors, both for energy (kWh) and demand (kW), resulting from the transmission of electricity from the busbar to the principal delivery voltage levels at which sales are made. If different loss factors apply to peak and off-peak losses, both sets of loss factors shall be provided.

(d) *Effective date of rate changes.* If a rate change for some or all of the

classes goes into effect during the reporting period, the utility shall report the effective date of the rate change and the approximate date on which bills are first received under the new rate for each class. If automatic adjustment clauses for any month result in a rate adjustment of more than 10 percent of the previous month's rate, that month shall be so designated.

(e) *Shifts on and off daylight savings time.* The utility shall report the hour, day and month of shifts on and off daylight savings time, if applicable, and shall report the time zones in which the retail load is located.

Subpart E—Calculated Costs

§ 290.501 Accounting cost calculations.

(a) *Calculated accounting costs of providing service.* The utility shall calculate the accounting costs of providing service by costing period, customer class, and voltage level and shall complete a summary Table 1. The table shall be completed for each jurisdiction in which the utility operates, unless the utility can show that the jurisdictional variation is not significant. If a method for calculating accounting costs has been specified by State law or by the State regulatory authority having rate approval authority over the utility, the calculation method used by the utility shall be consistent with such method. In the case of a non-regulated utility, the calculation method used shall be consistent with any legal constraint upon such utility's rate-making procedure.

(b) *Description of method used.* The reporting utility shall describe the method used for the calculations specified in paragraph (a) of this section.

(c) *Cost study.* The reporting utility shall provide a copy of any cost study upon which the information entered in the summary Table 1 is based, or certify that such study has been conducted and will be made available upon request.

(d) *Alternative submission of information.* If a recent, fully allocated retail class cost of service study has been made, the utility may submit that study in lieu of the information specified in this section and in subpart B (regarding accounting cost information) if such study includes all information specified in this section and that subpart.

§ 290.502 Marginal cost calculations.

(a) *Calculated marginal costs of providing service.* The utility shall calculate the marginal costs of providing service by costing period, customer class, and voltage level and shall complete and submit a summary Table 2. The table shall be completed for each jurisdiction in which the utility operates, unless the utility can show that the jurisdictional variation is not significant. If a method for calculating marginal costs has been specified by State law or by the State regulatory authority having rate approval authority over the utility, the calculation method used by the utility shall be consistent with such method. In the case of a non-regulated utility, the calculation method used shall be consistent with any applicable legal constraints upon such utility's rate-making procedure.

(b) *Description of method used.* The utility shall describe the method used for the calculations specified in paragraph (a) of this section, including

(1) A description of how demand related costs were determined for different costing periods.

(2) A listing of the different components of demand related costs (marginal generation, transmission, and distribution capacity costs) and how such costs were calculated.

(3) The marginal energy costs calculated in § 290.303.

(4) A listing of the different components of customer costs and how such costs were calculated.

(c) *Cost study.* The utility shall provide a copy of the cost study upon which the information entered in the summary Table 2 is based or certify that such study has been conducted and will be made available upon request.

(d) *Alternative submission of information.* If a recent, retail class marginal cost of service study has been made, the utility may submit that study in lieu of the information specified in this section and in Subpart C (regarding marginal cost information) if such study includes all information specified in this section and that subpart.

TABLE 1.—*Illustrative Summary of Accounting Costs by Costing Period, Customer Class and Voltage Level*

Customer Class and Voltage Level	Costing Period				Annual Customer Cost
	Peak Hours		Off-Peak Hours		
	I	II	III	IV	
Customer Class A:					$/customer
Voltage Level 1					
Demand Costs:					
Generation	$/kW	$/kW	$/kW		
Transmission	$/kW	$/kW	$/kW		
Distribution	$/kW	$/kW	$/kW		
Energy Costs	¢/kWh	¢/kWh	¢/kWh	¢/kWh	$/customer
Voltage Level 2					
Demand Costs:					
Generation	$/kW	$/kW	$/kW		
Transmission	$/kW	$/kW	$/kW		
Distribution	$/kW	$/kW	$/kW		
Energy Costs	¢/kWh	¢/kWh	¢/kWh	¢/kWh	
Customer Class B:					$/customer
Voltage Level 1					
Demand Costs:					
Generation	$/kW	$/kW	$/kW		
Transmission	$/kW	$/kW	$/kW		
Distribution	$/kW	$/kW	$/kW		
Energy Costs	¢/kWh	¢/kWh	¢/kWh	¢/kWh	

N.B.—Both the number and designation of the costing periods, customer classes, and voltage levels shown in this table are illustrative. They are not intended to suggest any constraint on the reporting utility's choice of the specifications most appropriate to its operations. The costing periods, customer classes, and voltage levels chosen, however, should be clearly specified either in the table headings or in footnotes.

TABLE 2.—*Illustrative Summary of Marginal Costs by Costing Period, Customer Class and Voltage Level*

Customer Class and Voltage Level	Costing Period				Annual Customer Cost
	Peak Hours		Off-Peak Hours		
	I	II	III	IV	
Customer Class A:					$/customer
Voltage Level 1					
Demand Costs:					
Generation	$/kW	$/kW	$/kW		
Transmission	$/kW	$/kW	$/kW		
Distribution	$/kW	$/kW	$/kW		
Energy Costs	¢/kWh	¢/kWh	¢/kWh	¢/kWh	$/customer
Voltage Level 2					
Demand Costs:					
Generation	$/kW	$/kW	$/kW		
Transmission	$/kW	$/kW	$/kW		
Distribution	$/kW	$/kW	$/kW		
Energy Costs	¢/kWh	¢/kWh	¢/kWh	¢/kWh	
Customer Class B:					$/customer
Voltage Level 1					
Demand Costs:					
Generation	$/kW	$/kW	$/kW		
Transmission	$/kW	$/kW	$/kW		
Distribution	$/kW	$/kW	$/kW		
Energy Costs	¢/kWh	¢/kWh	¢/kWh	¢/kWh	

N.B.—Both the number and designation of the costing periods, customer classes, and voltage levels shown in this table are illustrative. They are not intended to suggest any constraint on the reporting utility's choice of the specifications most appropriate to its operations. The costing periods, customer classes, and voltage levels chosen, however, should be clearly specified either in the table headings or in footnotes.

Subpart F—Exemptions and Extensions

§ 290.601 Exemptions.

(a) *Application.* Any electric utility may apply for an exemption from all or part of the requirements set forth in Subparts A through E of this part by filing an application at least 1 year prior to the time the information would otherwise be required, which application shall contain the following information:

(1) The name and location of the applicant.

(2) The nature and duration of the exemption sought, including a list of the requirements set forth in Subparts

A through E of this part for which each exemption is sought and information explaining why the gathering of such information will not be likely to carry out the purposes of section 133 of PURPA.

(3) A plan of compliance setting forth the utility's plan for full compliance with the rules in terms of the steps which the utility will take to obtain the required information and the time when the information will be supplied.

(4) A statement of any action taken by a State regulatory authority in response to an application made by the utility under paragraph (b) of this section, together with any statement of concurrence by a State regulatory authority, if any.

(b) *Concurring statement by State regulatory authority.* Each electric utility which is regulated by a State regulatory authority and which applies for an exemption under paragraph (a) of this section, shall apply to each State regulatory authority having jurisdiction over such utility for a statement of concurrence with the exemption sought.

(c) *Requests by State regulatory authorities.* A State regulatory authority may act on behalf of 1 or more utilities subject to its regulation in requesting a total or partial exemption. Such requests shall be filed at least 1 year prior to the time the information would otherwise be required and shall contain the following information:

(1) The name and location of the utility for which the exemption is sought.

(2) The nature and duration of the exemption sought including a list of the requirements set forth in Subparts A through E of this part for which each exemption is sought and information explaining why the gathering of such information will not be likely to carry out the purposes of section 133 of PURPA.

(d) *Public notice and comment.* (1) Within 15 days following receipt of the completed application for exemption submitted in accordance with paragraphs (a) or (c) of this section:

(i) The application shall be noticed in the FEDERAL REGISTER.

(ii) The utility shall apply to each State regulatory authority by which it is regulated to have such application published in the official state publication, if any, in which rate change applications are usually noticed.

(iii) The utility shall have such application published in a sufficient number of newspapers of general circulation in the applicable jurisdictions so as to give widest practicable notice to interested parties.

(2) A period of 45 days shall be permitted for receipt of written data, views, arguments, or other comments on the application, which period shall commence at the time all requirements imposed in paragraph (d)(1) of this section have been fulfilled.

(3) Additional information required for purposes of review and evaluation of the application may be requested by Commission Staff.

(4) Within 15 days following the conclusion of the comment period, the applicant may file reply comments.

(e) *Scope of exemption.* A reporting utility must submit a separate application for each information filing from which it seeks a partial or total exemption. An exemption granted by the Commission shall apply only to the next information filing required under § 290.102, unless otherwise specifically provided by the Commission.

§ 290.602 Extensions.

(a) *Applications.* Any electric utility may apply for an extension of the 2-year deadline for the filing of all or part of the information required under this part. Such application must be made no less than 180 days prior to the time the information filing would otherwise be required, and must contain the following information:

(1) The name and location of the applicant.

(2) A description of the information requirements for which the extension is sought, including the length of the proposed extension.

(3) A showing of good cause for the extension sought.

(4) A statement describing plans for application for, or proposal of, any rate increase during the period covered by the extension.

(5) A statement of any action taken by a State regulatory authority in response to an application made by the utility under paragraph (d) of this sec-

tion, together with the statement of concurrence by the State regulatory authority, if any.

(6) A plan of compliance setting forth the utility's plan for full compliance with the rules in terms of the steps which the utility will take to obtain the required information and the time when the information will be supplied.

(b) *Additional information.* Additional information required for purposes of review and evaluation of the application may be requested by Commission Staff.

(c) *Comments by interested parties.* The Commission may seek comments from interested parties on applications for extensions.

(d) *Concurring statement by State regulatory authority.* Each electric utility which is regulated by a State regulatory authority and which applies for an extension under paragraph (a) of this section, must apply to each State regulatory authority having jurisdiction over such utility for a statement of concurrence with the extension sought.

Subpart G—Enforcement

§ 290.701 Enforcement provisions.

(a) *Applicability.* It shall be unlawful for any person to violate any provision of this part. Pursuant to section 133(d) of PURPA, any person that violates any provision of this part shall be subject to those sanctions prescribed in paragraph (b) of this section.

(b) *Sanctions.* The following sanctions are prescribed for violation of this part:

(1) Whoever violates any provision of this part shall be subject to a civil penalty of not more than $2,500 for each violation.

(2) Whoever willfully violates any provision of this part shall be fined not more than $5,000 for each violation.

(3) Whenever it appears to the Commission or to its designee that any individual or organization has engaged, is engaged, or is about to engage in acts or practices constituting a violation of this part, the Commission or its designee may request the Attorney General to bring a civil action to enjoin such acts or practices, and upon a proper showing, a temporary restraining order or a preliminary or permanent injunction shall be granted without bond. In such action, the court may also issue mandatory injunctions commanding any person to comply with any provision, the violation of which is prohibited by paragraph (a) of this section.

(4) Any person suffering legal wrong because of any act or practice arising out of any violation of paragraph (a) of this section may bring a civil action for appropriate relief, including an action for a declaratory judgment or writ of injunction. United States district courts have jurisdiction of actions under this subparagraph without regard to the amount in controversy. Nothing in this subparagraph shall authorize any person to recover damages.

APPENDIX A

[Docket No. ERA-R-78-25]

REQUIREMENT FOR STATE AND LOCAL AGENCIES TO NOTIFY THE DEPARTMENT OF ENERGY OF THEIR RATEMAKING AUTHORITY OVER GAS AND ELECTRIC UTILITIES COVERED BY TITLES I AND III OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 AND TITLE II OF THE NATIONAL ENERGY CONSERVATION POLICY ACT OF 1978

AGENCY: Economic Regulatory Administration (ERA), Department of Energy (DOE).

ACTION: Notice.

SUMMARY: Sections 102(c) and 301(d) of the Public Utility Regulatory Policies Act (PURPA) (Pub. L. 95-617) and section 211(b) of the National Energy Conservation Policy Act (NECPA) (Pub. L. 95-619) require the Secretary of Energy to publish lists, before the beginning of each calendar year, identifying each gas utility and electric utility to which Titles I and III of PURPA and Part 1 of Title II of NECPA, apply during such calendar year. This Notice includes the list for 1979 and requires each State regulatory authority to notify the Secretary of Energy of each gas and electric utility on the list for which such State regulatory authority has ratemaking authority. This Notice also requests public comment on the accuracy of the list of gas utilities and electric utilities.

DATE: State regulatory authorities must respond in writing on or before January 29, 1979. Other written comments on the accuracy of the lists should also be received by January 29, 1979.

ADDRESS: State regulatory authorities must send 15 copies of the required written response to: Department of Energy, Office of Public Hearing Management, Room 2313, 2000 M Street, NW., Docket No. ERA-R-78-25, Washington, D.C. 20461, Telephone: (202) 254-5201.

Other persons or organizations wishing to comment on the accuracy of the lists should send 5 copies of written comments to the address above.

Letters should include the writer's name, address and telephone number.

FOR FURTHER INFORMATION CONTACT:

Jeffrey A. Serfass, Office of Utility Systems Economic Regulatory Administration, Department of Energy, 2000 M Street, NW. (Vanguard 538), Washington, D.C. 20461, Telephone: (202) 254-9700.

NOTICE

As required by the Public Utility Regulatory Policies Act (PURPA), sections 102(c) and 301(d), and the National Energy Conservation Policy Act (NECPA), section 211(b), hereinafter referred to as the "Act(s)", the U.S. Department of Energy (DOE) is publishing the following list of utilities which sell natural gas and electricity and will be covered by the Act(s) in 1979. As further required by the Act(s), State regulatory authorities are to notify the Secretary of Energy as to their ratemaking authority over listed utilities. One of the chief purposes of this Notice is to inform utilities, other government agencies, and interested persons as to which utilities are covered by the two Act(s). The inclusion or exclusion of any utility does not affect the legal obligations of such utility or the responsible State regulatory authority under the Act(s).

The term "State regulatory authority" means any agency of the 50 States, the District of Columbia or Puerto Rico (or political subdivision thereof), which has authority to fix, modify, or approve rates for the sale of electric energy or natural gas by any utility (other than by such State agency), except that in the case of a utility for which the Tennessee Valley Authority (TVA) has ratemaking authority, the term "State regulatory authority" means the TVA.

Title I of PURPA (Pub. L. 95-617) deals with retail regulatory policies for electric utilities. Section 102(c) requires the Secretary of Energy to publish a list, before the beginning of each calendar year, identifying each electric utility to which Title I applies during such calendar year. An electric utility is defined as any person, State agency or Federal agency, which sells electric energy. An electric utility is covered by Title I for any calendar year if the electric utility had total sales of electric energy for purposes other than resale in excess of 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. An electric utility is covered in 1979 if it exceeded the threshold in 1976 or 1977.

Title III of PURPA deals with retail policies for natural gas utilities. Section 301(d) of Title III requires the Secretary of Energy to publish a list, before the beginning of each calendar year, identifying each gas utility to which Title III applies during such calendar year. A gas utility is defined as any person, State agency or Federal agency, engaged in the local distribution and the sale of natural gas to any ultimate consumer of natural gas. A gas utility is covered by Title III for any calendar year if the gas utility had total sales of natural gas for purposes other than resale in excess of 10 billion cubic feet during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. A gas utility is covered in 1979 if it exceeded the threshold in 1976 or 1977.

Title II, Part 1, of NECPA (Pub. L. 95-619) deals with residential conservation programs. Section 211(b) also contains a requirement to publish a list of electric and gas utilities. The NECPA requirements for coverage of gas utilities and electric utilities are different in three respects:

(1) The threshold for electric utilities is 750 million kilowatt-hours for purposes other than resale;

(2) A utility is covered for any calendar year if it exceeded the threshold during the second preceding calendar year. A utility is covered in 1979 if it exceeded the threshold in 1977; and

(3) Only utilities which have some residential sales are covered.

The following list covers both PURPA and NECPA requirements, with exceptions noted for listed utilities not covered by NECPA. The list is alphabetical, but subdivided into electric utilities and gas utilities and further subdivided by type of ownership: privately-owned, publicly-owned, and rural cooperative.

All electric utilities, except those marked (*), are covered by both the regulatory policy provisions of PURPA Title I *and* the residential conservation provisions of NECPA. All gas utilities, except those marked (*), are covered by both the regulatory policy provisions of PURPA Title III, and the residential conservation provisions of NECPA. Those electric utilities marked (8) are *not* covered by NECPA.

No later than January 29, 1979, each State regulatory authority must notify the Department of Energy of each utility on the list over which it has ratemaking authority. Such notification must include appropriate legal citations, and for any listed utility known to be subject to other ratemaking authorities within the State for other portions of its service area, a precise description of the portion to which such notification applies. In the event that more than one agency claims ratemaking authority over

the same service area of any listed utility, the Secretary will request such agencies to identify the lead agency for purposes of PURPA and NECPA compliance, reporting, and eligibility for financial assistance.

All interested persons including State regulatory authorities, are invited to comment on any errors or omissions with respect to the list.

ELECTRIC UTILITIES

All utilities listed below had electric energy sales, for purposes other than resale, in excess of 500 million kilowatt-hours in 1976 or 1977. All, except those marked (*), are covered by PURPA Title I and NECPA Title II. Utilities marked (*) either do not exceed the NECPA threshold of 750 million kilowatt-hours in 1977 or do not have residential sales and, therefore, they are not covered by NECPA Title II.

INVESTOR-OWNED

Alabama Power Company
*Alcoa Generating Corporation
Appalachian Power Company
Arizona Public Service Company
Arkansas-Missouri Power Company
Arkansas Power & Light Company
Atlantic City Electric Company
Baltimore Gas & Electric Company
Bangor Hydro-Electric Company
Black Hills Power & Light Company
Blackstone Valley Electric Company
Boston Edison Company
Brockton Edison Company
California-Pacific Utilities Company
Cambridge Electric Light Company
Carolina Power & Light Company
Central Hudson Gas & Electric Corporation
Central Illinois Light Company
Central Illinois Public Service Company
Central Louisiana Electric Company
Central Maine Power Company
Central Power & Light Company
Central Telephone & Utilities Corporation
Central Vermont Public Service Corporation
Cincinnati Gas & Electric Company
Citizens Utilities Company
Cleveland Electric Illuminating Company
Columbus & Southern Ohio Electric Company
Commonwealth Edison Company
Community Public Service Company
Connecticut Light & Power Company
Consolidated Edison Company of New York
Consumers power Company
Dallas Power & Light Company
Dayton Power & Light Company
Delmarva Power & Light Company
Detroit Edison Company
Duke Power Company
Duquesne Light Company
El Paso Electric Company
Electric Energy, Incorporated
Empire District Electric Company
*Fall River Electric Light Company
Florida Power Corporation
Florida Power & Light Company
Georgia Power Company
Green Mountain Power Corporation
Gulf Power Company
Gulf States Utilities Company
Hartford Electric Light Company
Hawaiian Electric Company
Houston Lighting & Power Company
Idaho Power Company
Illinois Power Company
*Indiana & Michigan Electric Company
Indianapolis Power & Light Company
Interstate Power Company
Iowa Electric Light & Power Company
Iowa-Illinois Gas & Electric Company
Iowa Power & Light Company
Iowa Public Service Company
Iowa Southern Utilities Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas & Electric Company
Kansas Power & Light Company
Kentucky Power Company
Kentucky Utilities Company
Kingsport Power Company
*Lake Superior District Power Company
Long Island Lighting Company
Louisiana Power & Light Company
Louisville Gas & Electric Company
Madison Gas & Electric Company
Massachusetts Electric Company
Metropolitan Edison Company
Minnesota Power & Light Company
Mississippi Power Company
Mississippi Power & Light Company
*Missouri Edison Company
Missouri Power & Light Company
Missouri Public Service Company
Missouri Utilities Company
Monongahela Power Company
Montana-Dakota Utilities Company
Montana Power Company
Narragansett Electric Company
Nevada Power Company
New Bedford Gas & Edison Light Company
*New Mexico Electric Service Company
New Orleans Public Service
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Northern Indiana Public Service Company
Northern States Power Company
*Northwestern Public Service Company
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Corporation
Oklahoma Gas & Electric Company
*Old Dominion Power Company
Orange & Rockland Utilities
Otter Tail Power Company
Pacific Gas & Electric Company
Pacific Power & Light Company
Pennsylvania Electric Company
Pennsylvania Power & Light Company
Pennsylvania Power Company
Philadelphia Electric Company
Portland General Electric Company
Potomac Edison Company

Potomac Electric Power Company
Public Service Company of Colorado
Public Service Company of Indiana
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Company of Oklahoma
Public Service Electric & Gas Company
Puget Sound Power & Light Company
Rochester Gas & Electric Corporation
Rockland Electric Company
St. Joseph Light & Power Company
San Diego Gas & Electric Company
Savannah Electric & Power Company
Sierra Pacific Power Company
South Carolina Electric & Gas Company
Southern California Edison Company
Southern Indiana Gas & Electric Company
Southwestern Electric Power Company
*Southwestern Electric Service Company
Southwestern Public Service Company
Tampa Electric Company
Texas Electric Service Company
Texas Power & Light Company
Toledo Edison Company
Tucson Gas & Electric Company
*UGI Corporation
Union Electric Company
Union Light, Heat & Power Company
United Illuminating Company
*Upper Peninsula Power Company
Utah Power & Light Company
Virginia Electric & Power Company
Washington Water Power Company
West Penn Power Company
West Texas Utilities Company
Western Massachusetts Electric Company
Wheeling Electric Company
Wisconsin Electric Power Company
Wisconsin Michigan Power Company
Wisconsin Power & Light Company
Wisconsin Public Service Corporation

PUBLICLY-OWNED

*Albany Water, Gas & Light Commission
Anaheim—Electrical Division
Austin Electric Department
*Bristol Electric System (TN)
*Bryan Municipal Electric System (TX)
*Burbank Public Service Department
Central Lincoln People's Utility District (OR)
Chatanooga Electric Power Board
*Clatskanie People's Utility District (OR)
*Cleveland Division of Light & Power (OH)
*Cleveland Utilities (TN)
Colorado Springs Department of Put Utilities
Decatur Electric Department (AL)
*Detroit Public Lighting Department
Eugene Water & Electric Company
Fayetteville Public Works Commission (NC)
*Florence Electricity Department (AL)
*Gainesville-Alachua County Regional Electric, Water, and Sewer Utilities Boc (FL)
Garland Electric Department (TX)
*Glendale Public Service Department (CA)
*Greeneville Light & Power System (TN)
*Greenville Utilities Commission (NC)
Huntsville Utilities (AL)
Imperial Irrigation District (CA)
*Independence Power & Light Department (MO)
*Jackson Utility Division—Electric Department (TN)
Jacksonville Electric Authority (FL)
Johnson City Power Board (TN)
Kansas City Board of Public Utilities (KS)
Knoxville Utility Board (TN)
*Lafayette Utility System (LA)
Lakeland Department of Electricity and Water (FL)
Lansing Board of Water & Light (MI)
Lincoln Electric System (NB)
Los Angeles Department of Water and Power
Lower Colorado River Authority
*Lubbock Power & Light (TX)
Memphis Light, Gas & Water Division (TN)
Modesto Irrigation District (CA)
*Muscatine Power & Water (IA)
Nashville Electric Service (TN)
Nebraska Public Power District
Omaha Public Power District
Orlando Utilities Commission (FL)
*Palo Alto Electric Utility (CA)
*Pasadena Water & Power Department (CA)
*Power Authority of New York
*Port Angeles Light & Water Department (WA)
*Public Utility District No. 1 of Benton County (WA)
*Public Utility District No. 1 of Chelan County (WA)
Public Utility District No. 1 of Clark County (WA)
Public Utility District No. 1 of Cowlitz County (WA)
*Public Utility District No. 1 of Douglas County (WA)
Public Utility District of Grant County (WA)
Public Utility District No. 1 of Grays Harbor County (WA)
*Public Utility District No. 1 of Lewis County (WA)
Public Utility District No. 1 of Snohomish County (WA)
Puerto Rico Water Resources Authority of Puerto Rico
*Richmond Power & Light (IN)
Riverside Public Utilities (CA)
*Rocky Mountain Public Utilities (NC)
Sacramento Municipal Utility District (CA)
Salt River Project Agricultural Improvement and Power District (AZ)
San Antonio Public Service Board (TX)
*San Francisco Public Utilities Commission
Santa Clara Electric Department (CA)
Seattle Department of Lighting (WA)
South Carolina Public Service Authority
Springfield City Utilities (MO)
*Springfield Utilities Board (OR)
Springfield Water, Light & Power Department (IL)
Tacoma Public Utilities—Light Division (WA)

*Taunton Municipal Lighting Plant (MA)
*Turlock Irrigation District (CA)
Vernon Municipal Light Department (CA)
*Wilson Utilities Department (NC)

RURAL ELECTRIC COOPERATIVES

*Appalachian Electric Cooperative
*Chugach Electric Association
*Clay Electric Cooperative
Cumberland Electric Membership Corporation
*Duck River Electric Membership Corporation
*First Electric Cooperative Corporation
*Four County Electric Power Association
*Gibson County Electric Membership Corporation
Green River Electric Corporation
Henderson-Union Rural Electric Cooperative Corporation
*Jackson Electric Membership Corporation
*Lee County Electric Cooperative
*Meriwether Lewis Electric Cooperative
Middle Tennessee Electric Membership Corporation
*Moon Lake Electric Association
*Pedernales Electric Cooperative
*Pennyrile Rural Electric Cooperative Corporation
*Singing River Electric Power Association
*South Central Power Company
Southern Maryland Electric Cooperative
*Southern Pine Electric Power Association
*Southwest Louisiana Electric Membership Corporation
*Southwest Tennessee Electric Membership Corporation
*Tri-County Electric Membership Corporation
*Umatilla Electric Cooperative Association
*Upper Cumberland Electric Membership Corporation
Volunteer Electric Cooperative
*Warren Rural Electric Cooperative
*West Kentucky Rural Electic Cooperative Corporation

FEDERAL AGENCIES

*Bonneville Power Administration
*Tennessee Valley Authority
*Western Area Power Administration

GAS UTILITIES

All utilities listed below had natural gas sales, for purposes other than resale in excess of 10 billion cubic feet in 1976 or 1977. All except those marked (*), are covered by PURPA Title III and NECPA Title II. Utilities marked (*) either do not exceed the threshold in 1977 or do not have residential sales and, therefore, are not covered by NECPA Title II.

INVESTOR-OWNED

Alabama Gas Corporation
*Alabama-Tennessee Natural Gas Company
Alaska Gas & Service Company
*Anadarko Production Company
Arizona Public Service Company
Arkansas-Louisiana Gas Company
Arkansas-Oklahoma Gas Company
Arkansas Western Gas Company
Atlanta Gas light Company
Baltimore Gas & Electric Company
Bay State Gas Company
Boston Gas Company
Brooklyn Union Gas Company
Cabot Corporation Utility Division
California-Pacific Utilities
Carnegie Natural Gas Company
Carolina Pipeline Company
Cascade Natural Gas Corporation
Central Florida Gas Corporation
Central Illinois Light Company
Central Illinois Public Service Company
Central Louisiana Electric Company
Chattanooga Gas Company
Cheyenne Light, Fuel and Power Company
Cincinnati Gas and Electric Company
Cities Service Gas Company
Citizens Gas and Coke Utility
*Colorado Interstate Gas Company
Columbia Gas System
Commonwealth Gas Company
Connecticut Light & Power Company
Connecticut Natural Gas Corporation
Consolidated Edison Company of New York
Consolidated Gas Supply Corporation
Consumers Power Company
Dayton Power & Light Company
Delmarva Power & LIght Company
East Ohio Gas Company
*East Tennessee Natural Gas Company
Elizabethtown Gas Company
*El Paso Natural Gas Company
Entex, Incorporated
Equitable Gas Company
Florida Gas Company
*Florida Gas Transmission Company
Gas Light Company of Columbus
Gas Service Company
Gulf States Utilities Company
Houston Natural Gas Corporation
Illinois Power Company
Indiana Gas Company
Inland Gas Company
Inter City Gas Limited
Intermountain Gas Company
Interstate Power Company
Iowa Electric Light & Power Company
Iowa Illinois Gas & Electric Company
Iowa Power & Light Company
Iowa Public Service Company
Iowa Southern Utilities Company
Kansas-Nebraska Natural Gas Company
Kansas Power & Light Company
Kokomo Gas & Fuel Company
Laclede Gas Company Consolidated
Lone Star Gas Company
Long Island Lighting Company
Louisiana Gas & Electric Company
Louisiana Gas Service Company
Louisiana Intrastate Gas Corporation
Louisville Gas & Electric Company
Lowell Gas Company
Madison Gas & Electric Company
Metropolitan Utilities District of Omaha

Michigan Consolidated Gas Company
Michigan Gas Utilities Company
Michigan Power Company
Minnesota Gas Company
*Mississippi River Transmission Corporation
Mississippi Valley Gas Company
Missouri Public Service Company
Mobil Gas Service Corporation
Montana-Dakota Utilities Company
Montana Power Company
Mountain Fuel Supply Company
Nashville Gas Company
National Fuel Gas Distribution Corporation
New Jersey Natural Gas Company
New Orleans Public Service
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
North Carolina Natural Gas Corporation
North Central Public Service Company
North Penn Gas Company
North Shore Gas Company
Northern Illinois Gas Company
Northern Indiana Public Service Company
Northern Natural Gas Company
Northern States Power Company
Northwest Natural Gas Company
Northwestern Public Service Company
Oklahoma Gas & Electric Company
Oklahoma Natural Gas Company
Orange & Rockland Utilities
Pacific Gas & Electric Company
Panhandle Eastern Pipeline Company
Pennsylvania Gas & Water Company
People's Gas Light & Coke Company
Peoples Gas System
Peoples Natural Gas Company
Philadelphia Electric Company
Phillips Gas & Oil Company
Phillips Natural Gas Company
Phillips Petroleum Company
Piedmont Natural Gas Company
Pioneer Natural Gas Company
Providence Gas Company
Public Service Company of Colorado
Public Service Company of North Carolina
Public Service Electric & Gas Company
Rochester Gas & Electric Corporation
San Diego Gas & Electric Company
Sierra Pacific Power Company
South Carolina Electric & Gas Company
South Jersey Gas Company
Southeast Alabama Gas District
Southeastern Michigan Gas Company
Southern California Gas Company
Southern Connecticut Gas Company
Southern Indiana Gas & Electric Company
Southern Natural Gas Company
Southern Union Gas Company
Southwest Gas Corporation
Terre Haute Gas Corporation
*Texas Eastern Transmission Corporation
Texas Utilities
Tucson Gas & Electric Company
UGI Corporation
Union Gas Systems
Union Light, Heat & Power Company
United Cities Gas Company
United Gas Pipeline Company
Virgina Electric Power Company
Washington Gas Light Company
Washington Natural Gas Company
Washington Water Power Company
West Ohio Gas Company
Western Gas Corporation
Western Kentucky Gas Company
Western Slope Gas Company
Wisconsin Fuel & Light Company
Wisconsin Gas Company
Wisconsin Natural Gas Company
Wisconsin Power & Light Company
Wisconsin Public Service Corporation

APPENDIX B

STAFF DISCUSSION OF THE MARGINAL COST INFORMATION REQUIRED UNDER THE PROPOSED RULES

Introduction

The marginal cost data gathered pursuant to Subpart C, together with the load data collected in accordance with Subpart D, should provide the information necessary for utilities (as well as state regulatory authorities and intervenors) to calculate the extent to which the total cost of supplying electric power is likely to change if (1) additional capacity is added to meet peak demand, (2) additional kilowatt-hours of electric energy are delivered ot customers, or (3) additional customers are added to the distribution system. In addition, the data will permit identification of differences in the marginal costs of serving various classes of customers that can be attributed to receiving electricity at different voltage levels and to variations in hourly, daily and seasonal time of use.

Marginal Cost—A General Framework

In general, marginal cost is defined as the expected change in the total cost of supplying one additional unit of output. In the electric utility industry, the change in output can be viewed as having three separate cost dimensions: the additional cost of supplying an additional kilowatt-hour of electricity (marginal energy cost), the additional cost of supplying an additional kilowatt of capacity, including the cost of maintaining adequate reserve capacity (marginal capacity or demand cost),[1] [2] and the addi-

[1] Marginal capacity (or demand) cost can be further delineated as marginal generation capacity cost, marginal transmission capacity cost, and marginal distribution capacity cost.

[2] For capacity cost, the ideal would be to measure the change in costs for a one kW change in capacity. In most instances, this calculation cannot be performed since generating plants are typically available only in much larger blocks of capacity. Therefore, it will generally be necessary to estimate the cost of a one kW charge by dividing the change in total cost by the total change in kW capacity.

tional cost of adding a new customer (marginal customer cost). Demand cost is measured per kilowatt (kW) of additional demand, energy cost per kilowatt-hour (kWh) of additional consumption, and customer cost per additional customer served.

Marginal costs can be calculated on a short-run, intermediate-run or long-run basis. In economic theory, these terms are used to refer to the conditions and constraints under which it is assumed that a firm is responding to a change in demand. Short-run marginal costs are the additional cost that would be incurred by the firm to satisfy an increase in demand with existing plant and equipment. Long-run marginal costs are the additional costs that would be incurred by the firm to meet an increase in demand with a completely optimal mix of plant and equipment, a mix that may bear little, if any, resemblance to the firm's existing plant and equipment. Along the same lines, intermediate run costs may be viewed as the additional costs that would result from meeting an increase in demand a mix of existing and new equipment.

An increase in demand will cause a firm to incur costs immediately, in the near future, and further into the future, regardless of which type of adaptation is assumed. For example, a correct calculation of short run marginal costs would required determining the change in total costs of production resulting from an increase in demand, even if these costs are expected to be incurred several years in the future. The same standard would also apply to the calculation of intermediate and long-run costs. In others words, any marginal cost calculation, short-, intermediate-, or long-run, requires estimating all additional costs that can be attributed to the projected increase in demand as far into the future as can be foreseen.[1]

The marginal cost approach has two major characteristics that distinguish it from the accounting cost approach. The first notion is that "cost causality" has to be defined in terms of costs that are likely to be incurred rather than costs that may already be recorded on the books. Implicit in this approach is the notion that "causality" should be viewed as a forward looking concept. That is, a change in the current pattern of demand is responsible for a change in costs only if a change in cost is caused by and occurs after a change in demand.

A second characteristic of the marginal cost approach is its emphasis on *changes* in cost. For example, most accounting cost methods require an allocation of all capacity costs, net of depreciation. Generally, the allocation is to customer classes. In contrast, the marginal cost approach considers only *changes* in capacity costs. Moreover, the marginal capacity costs are generally not allocated to customer classes but instead are assigned to costing periods based on the degree of likelihood that the system peak will occur during that period.

The information required in Subpart C of the proposed regulations can be used to calculate short run, intermediate and long-term marginal costs. While short-run marginal costs may be more appropriate for achieving efficient resource use, there may be practical considerations that would mandate the use of intermediate or long-run marginal costs. For example, a problem in calculating short-run marginal costs is that one of its components at the time of system peak, the probability of loss of load times a monetary estimate of the damage that such a loss of load would produce, may be difficult to calculate. Second, short-run marginal costs tend to exhibit more instability than intermediate- or long-run marginal costs. Therefore, if rates were to be established on the basis of short-run marginal costs, it could impair the ability of consumers to make rational choices and plan intelligently for the future. Since the degree of instability will vary among utilities, it will be left to the reporting utility to decide which type of marginal costs are to be reported for Table 2 (Illustrative Summary of Marginal Costs By Costing Period, Customer Class and Voltage Level). (See Subpart E.)

Reporting Requirements

The reporting requirements for marginal cost information are divided into seven sections in addition to the general instructions:

1. Generation cost information
2. Energy cost information
3. Transmission cost information
4. Distribution and customer cost information
5. Other cost information to be reported
6. Annual carrying charge rates
7. Costing periods

1. Generation cost information

The data collected in this section are used in the calculation of marginal generation capacity costs. Marginal generation capacity costs refer to the costs that would be incurred to meet a small permanent change in the level or pattern of kW demand. There are a number of methods currently proposed for calculating these costs. In general, each of the methods hypothesizes a change in load and then compares the costs that would be incurred to meet the changed load with the costs that would be incurred to meet the unchanged load. The difference in costs, when divided by the hypothesized kW change, constitutes an estimate of marginal

[1]To ease the reporting burden on utilities, estimates of future loads and costs are not required beyond ten years. A reporting utility may, however, supply load and cost estimates beyond ten years if it believes the longer time span provides a more accurate reflection of its planning efforts.

generation capacity costs. The calculation of marginal generation cost should take into account the need for maintaining reserve capacity and may take into account the impact of losses on the cost of supplying a kilowatt of electric power to different voltage levels.

Some care should be given to distinguishing generation capacity costs from generation capital costs. For example, an increment in demand may change the size or timing of a generation unit. If the operation of this unit produces fuel savings for the system, a correct calculation of generation capacity costs would require subtracting the monetary value of the fuel savings from the estimate of the unit's capital costs.

2. Energy cost information

The data collected in this section are used in the calculation of marginal energy costs. Marginal energy cost at any hour refers to the cost of fuel and variable operation and maintenance expenses incurred in producing an additional kWh of electricity. For example, the fuel and variable operation and maintenance cost of the most expensive machine on line may be the marginal energy cost. For a utility without adequate capacity of its own, the marginal energy cost is the cost of purchased energy.

There are exceptions to the "most expensive" machine rule. The most common examples are the need to run a machine with high running costs for purposes of area protection and voltage control or the need to keep an expensive unit on line at night because it will be required to meet load the next day. Even though these machines may be the most expensive machines on line at a particular time, their costs would not constitute the marginal energy costs of the system since the loading of these machines would be neither decreased or increased in response to further changes in demand.

3. Transmission cost information

The data collected in this section are used in the calculation of marginal transmission costs. This calculation involves determining the costs of additions to transmission systems that are causally related to system peak demand. These overall demand-related costs would include, at a minimum, both capital costs and fixed operation and maintenance expenses. General plant, working capital, and administrative and general expenses are additional components of demand-related transmission costs under certain costing methods.

It should be noted that the information requested in this section focuses on the overall cost of additions to transmission plant on an historic and projected basis. A possible refinement would involve subtracting from total transmission expenditures those expenditures that were incurred or are likely to be incurred in constructing remote generating plants or in building EHV lines in connection with pooling agreements.

4. Distribution and customer cost data

This section is designed to collect distribution system data necessary for the calculation of marginal distribution capacity- and customer-related costs. An electric distribution system performs two functions—the connection of customers to the system and the carrying of their maximum loads. Hence, distribution system costs should be separated into customer-related and capacity- (or demand-) related costs. Further, since connection costs and demand levels are likely to vary considerably among customers, these costs should be estimated for each customer class (and voltage level).

Operation and maintenance expenses associated with distribution are also collected in this section. The marginal overhead investment and expenses that, under certain costing methods, are added to the distribution costs, are requested in the next section.

5. Other cost information to be reported

The cost data required in this section have several purposes. Sales and customer account expenses together with the data on the number of customers in each class (Subpart D) are used, under certain methods, in the calculation of marginal customer cost. The marginal values of these expenses are approximated by adjusted historical data. In addition to these two items, the annual capital cost of a minimum distribution system may also be included as a component of customer costs.

Working capital and general plant investment as well as administrative and general expenses are used, under certain costing methods, in the calculation of the marginal capacity costs of generation, transmission and distribution. Here also, the marginal effects of these cost components are estimated using historical data.

6. Annual carrying charge rates

The purpose of this section is to obtain carrying charge rates used in the calculation of marginal capacity costs. The calculation of marginal capacity cost for generation, transmission, and distribution facilities involves the conversion of the incremental capital investments into annual charges for carrying and repaying the investments, as well as accounting for all other expenses created by the addition of those facilities. What is sought are level annual charges representing the annual revenue requirements that arise from the marginal investments. The annual carrying charge rates are intended to account for those charges that are most directly related to the level of the per kilowatt incremental investment in these facilities—namely, depreciation, return, income and property-related taxes,

and insurance. The data necessary to compute other related charges, such as plant-related operation and maintenance expenses, administrative and general expenses, general plant, and working capital requirements are dealt with in other sections.

Carrying charges can be and are computed in a variety of ways in investment analyses. However, to prevent the possible exclusion or duplication of some of these costs in the final calculations of marginal capacity costs, the Commission has chosen to specify the components to be included in the carrying charge rates as the four items indicated above. At the same time, allowance is made for differences in regulatory treatment of various items so that the resulting costs should be reflective of the cost considerations entering into the reporting utility's investment decisions. In situations where the reporting utility operates in more than one state the costing procedures are required to correspond to the prevailing regulatory prescriptions of the predominant regulatory authority unless the state-to-state differences would substantially affect the results. In the latter instance, the utility is required to report separate rates by jurisdiction.

Publicly owned utilities are required to calculate the carrying charge rates based on those cost considerations relevant to their system.

7. Costing periods

Since costing periods can ultimately serve as a basis for establishing pricing periods, costing periods should be selected so as to be intelligible to the consumer and to promote economic efficiency. If all consumers were sufficiently sophisticated and if the cost of perfect metering were very low, one could simply cost each hour of the year separately. However, since neither of the above conditions pertain, it makes sense to group hours of similar costs together and then make judgments which attempt to balance the goals of economic efficiency and consumer comprehension. Therefore, the general objectives in determining costing and pricing periods is to differentiate between periods of high costs and low costs (and, if appropriate, intermediate costs) of providing electric service. Typically, these cost levels closely follow periods of high and low demand.

It could be expected that on a typical weekday most utilities would be able to distinguish at least two costing periods. It is also likely that there will be sufficient variation in costs between seasons to justify seasonal distinctions in the daily costing periods. Therefore, at least four costing periods may be expected to result from the analysis required for this section.

Several approaches have been suggested for the determination of costing periods. One approach is to caluclate loss-of-load probabilities (LOLPs) for different hours in the future. Costing periods are determined by grouping together hours with similar LOLP values. The same LOLP values can also be used for determining the portion of capacity related costs that will be borne by each costing period. A second approach involves examining daily and seasonal system load curves. Hours of similar load are grouped together on the presumption that they reflect periods of similar cost.

It is not apparent that any one of these approaches is clearly preferable. Therefore, the proposed rule would permit each utility to pick the method that appears to be most suitable to its needs and then describe the assumptions and procedures required by that method. The level of description should be sufficient to allow informed non-company personnel to understand how the costing periods were selected.

APPENDIX C

STAFF DISCUSSION OF THE FORM 1 RAW INFORMATION PROPOSAL

Introduction

Section 133 of the Public Utilities Regulatory Policies Act (PURPA) requires the Federal Energy Regulatory Commission (Commission) to promulgate rules to govern the collection and reporting of information "necessary to allow determination of the costs associated with providing electric service."

The purpose of Section 133 as stated in the "Joint Explanatory Statement of the Committee of Conference" is to require electric utilities to gather information (under rules prescribed by the Commission) which is necessary to determine the costs associated with providing electric service and to provide for the filing and publication of this information. "The conferees intend that good information with regard to costs of providing service must be readily available on a timely basis to everyone concerned."

The ensuing proposal for rules under Section 133 attempts to provide all parties ready access to uniform and comprehensive information necessary for determining and assigning the costs of providing electric service. It adopts the view that the FERC should require utilities to submit information sufficient to accommodate the development of cost of service studies using applications of either fully allocated cost (accounting cost) or marginal cost principles.

A very large portion of the information required to perform cost of service calculations by either of the marginal cost methods or fully allocated cost methods are required to be reported annually by utilities in FERC Form 1 and Form 12. There is good reason to believe that it would lessen the burden on electric utilities, State Regulatory authorities, and the Commission if the Commission

were to utilize an existing reporting form, with amendments, for reporting purposes in accordance with Section 133 of PURPA. Therefore, this proposal would amend the current regulations, 18 CFR Part 141, Statements and Reports, which prescribes certain reports and statements jurisdictional utilities must file. Covered utilities would be required to file with the FERC and State regulatory authorities information required under Part 141.1 as would be amended.

OBLIGATIONS OF THE COMMISSION

In brief, the Commission is obligated under Section 133 of PURPA to require, at a minimum, that information is collected and is reported which allows to the extent it is practicable, the identification of:

(1) Customer, demand and energy costs components, to the maximum extent practicable;

(2) Costs of serving each customer class to include subgroups within classes, at different voltage levels, time of use and other appropriate factors;

(3) Daily and seasonal kilowatt load curves for the utility system and each customer class served under different rate schedules;

(4) Actual capital, maintenance and operating costs for transmission, distributing of electricity and for each generating unit; and

(5) Actual costs for purchased power reflecting daily and seasonal difference.

In addition, Section 133 requires the Commission to:

(6) Issue rules within 180 days after the enactment of the Act;

(7) Prescribe the methods, procedures, and format to be used by utilities in collecting the required information;

(8) Prescribe the manner in which utilities must make the required information, as reported to the Commission and any changes thereto at the time of an application for a rate increase, available to the public; and

(9) Periodically review its findings, if it has granted exemptions to the information collection and reporting regulation, as to whether collecting the information is not likely to carry out the purposes of Section 133.[1]

OBLIGATIONS OF ELECTRIC UTILITIES

The utilities, for their part, are required to file all information, except as specifically exempted by the Commission and except for information which may be proprietory, as regards bills and consumption patterns of individual customers, with the Commission and the State regulatory authority, and make it available to the public as prescribed by the Commission. In addition, utilities are required to make available for review by the Commission and the relevant state regulatory authority all information related to individual customers for verification of accuracy and enforcement purposes.

COMMISSION'S BROAD DISCRETION

With the exception of the four items required under subsections 133(a) (1), (2), (3), and (4) the Commission seems to have broad discretion to require utilities to report any information and in the form and manner as the Commission deems necessary to fulfill the purposes of section 133.

In that regard there are at least three options as to the kind of rule the Commission might issue. These options vary as to philosophy and amount of information to be collected and reported, and the costs incurred by the utility. Without discussing the merits the alternatives are as follows:

(1) The submission of cost of service studies using uniform account practices and test periods;

(2) Require the submission of using the accounting practices and test periods as required by the relevant state regulatory authority or as prescribed by management in the case of non-regulated utilities; or

(3) Require the submission of "raw information" sufficient to accommodate the development of cost of service studies based on either marginal cost or average fully allocated cost principles.

INFORMATION NEEDED FOR COSTING ANALYSES

In general, two costing methods and various applications of each are contemplated in this proposal, marginal cost and fully allocated cost methods.

In general, marginal cost methods are future oriented. They require information as to existing and future plant, costs and loads. Marginal cost methods seek to measure the change in total costs as a result of a change in output. To derive marginal costs one needs to examine the utility's costs plant, and loads retrospectively and prospectively.

Fully allocated cost methods, by contrast, focus on the present. They require information as to existing plant, costs and loads. Fully allocated cost methods attempt to measure actual total costs associated with providing a service. To derive fully allocated costs, one needs to examine the utility's costs incurred.

Both costing methods reflect the capital, operating and maintenance costs for generation, transmission, distribution and overhead, but for different time periods as indicated above.

[1] For detailed legal analysis of the Commission's authority and responsibilities under Section 133, see the memorandum of December —, 1978 from Peter Lesch to Commissioner Holden and a concurring memorandum of December —, 1978, from John O'Sullivan to Commissioner Holden.

In attempting to quantify costs of service the two methods employ different procedures. Hybrid models of each method may vary as to their application of these procedures and information requirements.

Notwithstanding the various hybrids, in general, the quantification of marginal costs involves determining: (1) costing periods, (2) marginal running (energy) costs, (3) marginal generating capacity (demand) costs, (4) marginal transmission capacity costs, (5) marginal distribution costs (demand and customer costs), and (6) marginal losses.

With respect to *costing periods*, what has to be determined are the time periods in which demand for electricity is likely to exceed the system's output capacity. It may also involve determining the amount of excess demand in each period. This analysis is significant to the marginalist approach as it would allow an identification of the periods to which higher costs should be assessed based on the need for additional capacity and the value of that capacity. The information requirements for this analysis may include:

(1) Total installed capacity;
(2) Contracts or arrangements for additional capacity, e.g., interconnection or power pool agreements;
(3) Equipment maintenance schedules;
(5) Probability of forced outages;
(6) Reserve requirements, and
(7) Total coincident demands at various times and voltage levels.

In computing *marginal running costs* the analyst attempts to identify the additional fuel and variable operations and maintenance expenses associated with providing service in each costing period for a specified future time (planning period). The objective is to determine the costs associated with estimates of additional energy production on the assumption that incremental energy costs will vary from energy costs that might be obtained if the system were operated under optimal conditions. Information necessary to perform a determination of marginal running costs include:

(1) Forecasted peak loads and load duration;
(2) Planned additions to plant;
(3) Forecasted energy production;
(4) Estimates of fuel and variable operations and maintenance expenses; and
(5) Purchased power costs.

As for *marginal generating capacity costs* the analyst attempts to determine the change in total generating capacity costs resulting from a change in generating capacity needed to meet additional demands. For this determination the following information for new or displaced machines is needed:

(1) Interest rate and cost of capital;
(2) Amount of reserved capacity;
(3) Schedule of future additions or reductions to generating plant including fuel type and kilowatt capacity;
(4) Annual fixed operation and maintenance; and
(5) Additional capacity available from other sources.

With respect to *marginal transmission capacity costs*, what needs to be determined are the costs of expanding transmission capacity as a result of expected growth in peak demand. The primary assumption is that transmission capacity is directly related to generation capacity which is a function of the system maximum demand (maximum coincident demand) and losses which occur in the process of transmitting and transforming electricity. Analyzing marginal transmission capacity costs requires information as to:

(1) Expected increase in system peak demand;
(2) Number and types of facilities, e.g., line voltage levels and switching stations;
(3) Per unit fixed capital costs for additional facilities;
(4) Annual fixed operation and maintenance expense;
(5) Transmission agreements with others; and
(6) An understanding of the system's transmission design procedures.

How *marginal distribution costs* should be derived is a matter to which there is no clear agreement among rate experts. The disagreement involves a proper distinction between customer-related distribution costs, i.e., costs directly related to adding a new customer and varying proportionately to the number of customers, and demand related distribution costs, i.e., costs associated with serving a particular load. There are many theories as to cost causation in distribution systems and perhaps a corresponding number of cost allocation methods. In general the following kinds of information is needed to determine marginal distribution costs by most methods:

(1) Number of customers;
(2) Coincident demands;
(3) Number and types of facilities, e.g., meters, poles, lines, transformer conductors;
(4) Per unit fixed capital costs for additional facilities; and
(5) Annual fixed operation and maintenance expense.

Another procedure performed in a marginal cost analysis is the computation of *marginal losses*. This procedure is necessary because energy losses affect marginal capacity and marginal energy costs for transmission and distribution. The size of the transmission and distribution facilities is related to the maximum load and energy losses during transmission and transformation. Generally speaking losses are calculated as a product of current and resistance. For

purposes of most costing analyses what needs to be determined is the difference between electricity input and electricity output, i.e., the difference of power generated and power delivered to customers at each voltage level. Information necessary for determining marginal energy losses include:

(1) Distance between the generation and ultimate delivery point;
(2) Number of power transformations;
(3) System peak demand;
(4) Customers' individual maximum demands; and
(5) Loads factors on and off peak; and
(6) Voltage level from which power is taken.

To develop fully allocated cost of service studies the analyst needs the following information from the electric utility's books in the test years rate base, depreciation, operation and maintenance expenses, taxes and cost of capital. These items are functionalized under the generation transmission and distribution functions. Also, for the test year, the analyst must have information as to the utility's expenses for fuel, variable operations and maintenance expenses, power purchases, customer accounting, sales promotion, administration and other (general). Finally, the analyst needs some information about customer demands and energy usage in the test year.

These are minimum information requirements essential to calculating either marginal costs or embedded costs studies. Some particular models of either approach may use more or less information, but the items specified above should suffice *most* applications.

Proposed Regulation

The following proposed regulation adopts the view that rules under Section 133 rules the Commission should require utilities to collect and report information which would accommodate the development of cost of service studies using applications of either marginal cost principles or average fully allocated cost principles.

This approach, raw information, appears consistent with the spirit and intent of the law as it relates to the obligations of state regulatory authorities and non-regulated utilities to consider and to make determinations as to certain Federal standards and the discretion reposed in both parties with respect to the utilization of any costing method deemed appropriate for making determinations as to the cost of service standard established in Section 115(a). It seems the Congress intended that State regulatory authorities and non-regulated utilities should have adequate information to fulfill their obligations under the Act but they should also have complete discretion as to the selection of costing methods in their deliberations. The Conference report specifically states:

> The Conferees chose the phrase "take into account" so as not to imply a reference for a State regulatory authority or non-regulated utility to follow any specific costing methodology for determining cost of service. The State regulatory authority or non-regulated authority *has discretion to select* which costing *methodology or methodologies it chooses*, consistent with State law. [Emphasis added.]

This "raw information approach," as do other proposals, recognizes that there is not general consensus or uniform application of either average fully allocated cost methods or marginal cost methods among rate experts. Within the same regulatory jurisdiction, some utilities are allowed to use different fully distributed embedded cost methods, i.e., average and excess demand, peak responsibility or non-coincident peak, or different marginal cost methods, for allocating costs and structuring rates. In addition this approach takes cognizance of the fact that there are still unresolved issues as regards to costing methods and rate design which are best dealt with by the relevant ratemaking authority. For example, in the design of time of use rates applying marginal cost principles, there are several approaches for calculating marginal costs which would yield similar but different cost estimates for the same utility system. There is the "peaker approach" based on the costs of peak demand and the carrying charges of a new combustion turbine. Another approach "system planning approach", attempts to simulate the manner in which the utility system is planned and dispatched at the lowest cost given a permanent increase in load. Marginal costs, under the "system planning approach", are the additional costs incurred to meet the additional load. A third approach, the "forward—backward approach, identifies the marginal generation capacity cost of meeting changes in peak demand using either the carrying charges of a baseload unit less fuel expenses saved or the carrying charges avoided as a result of bringing the unit on line earlier or later than planned. The "modified peaker approach, allocates marginal generation capacity costs to costing periods using relative marginal energy costs.

Allowing State regulatory authorities and non-regulated utilities broad latitude as to the choices of costing methods, the proposed regulation encourages discussion of theoretical issues; provides for the presentation of proposed resolutions to disputed issues in the regulatory arena; and allows utilities and State regulatory authorities to take in to account their specific environment and circumstances.

A very large portion of the information required for either generic approach are already contained in FERC Form—I with the exception of some information as to future

plant, costs, and loads. Since most electric utilities covered by Title I of PURPA must file the FERC Form—I annually, the raw information approach would utilize the form, with certain amendments, for section 133 purposes.

Several modifications of Form—I are proposed. One modification would be to amend schedules on pages 432 through 434 pertaining to generating plants so as to require information to be reported for each unit in a plant rather than for the plants on a aggregate basis. Another amendment to the same schedule would add a "line 46" which would require information as to heat rates at 100, 75, and 50 percent of rated capacity. A new "line 13" would be added which would require information as to maintenance requirements, in days, for generating plant.

The present "line 13" and following lines would be retained and renumbered "line 14" in seriatim. A new schedule relating to "planned additions to generating plant" would be added which would require for the next ten years and for each unit information as to:

(1) Plant-unit identification.
(2) If to be jointly owned, indicate expected percent ownership of unit's planned capability.
(3) Kind of unit (steam, internal combustion, gas turbine, nuclear, or hydroelectric).
(4) Planned date of commercial operation.
(5) Estimated earliest possible date of commercial operation.
(6) Expected plant life.
(7) Primary and secondary fuel types.
(8) Maximum generator nameplate rating (Kilowatts).
(9) Annual expected expenditures up to planned date of commercial operation (including AFUDC or CWIP earnings as applicable).
(10) Capital cost per kilowatt.
(11) Annual fixed operation and maintenance expenses.
(12) Cost of fuel per kilowatt-hour of net generator.
(13) Cost of fuel per million Btu.
(14) Heat rates at 100, 75, and 50 percent of rated capacity.
(15) Non-fuel variable operating costs per kilowatt-hour of net generation.
(16) Maintenance requirements (days of maintenance per year) for each of the first ten (10) years of commercial operation; if expected to change.
(17) Forced outage rates (percent) for each of the first ten (10) years of commercial operation.
(18) If unit is hydroelectric, provide the following, by month, for each of the first ten (10) years of commercial operation, if expected to change:
(i) kilowatt-hour production.
(ii) maximum continuous generating capability.

Note the above information would be the same as that required for existing plant with the three aforementioned modifications with the exception of information as to expected annual expenditures, "date of planned commercial operation" and "estimated earliest possible date of commercial operation."

Finally the schedule entitled "Electric Energy Account", page 431, would be amended to include a new part or subsection relating to information on class loads by time of day and by season. There would be certain provisions for the use of alternate information.

Under this proposal, utilities covered under section 133 would be required to file the above described information annually. Although class load information would be reported annually utilities would be required to conduct load research at least once every five years.

PURPA requires the filing of reports within two years of enactment of PURPA and "periodically, but not less frequently than every 2 years thereafter." Since most electric utilities either effect or apply for rate increases on an annual basis, the Commission would propose to require utilities covered under Section 133 to report cost of service information annually.

Filing requirements would apply to each utility's with annual electric operating revenues of $2,500,000 or more whether or not the utility is jurisdictional under the Federal Power Act and each electric utility that appears on the list as published by the Secretary of covered utilities as required by Section 133 of PURPA. Electric utilities not meeting this second criterion would be exempt from the requirement to report class load information and cost information relating to planned additions to plant. They would also be exempt from filing the several years of historic information relating to plant, sales, operations and loads.

Finally, for utilities covered under Section 133, there are certain exemptions and extensions for reporting requirements if specified conditions are met.

The Commission would propose to extend the initial filing period four months, March 31, 1981, beyond that prescribed in Section 133(c). It is believed that such extension of time would greatly lessen the unnecessary reporting burden for utilities, reduce administrative burden for the Commission, and aid the process of obtaining more complete and accurate information.

Appendix D—Public Law 95-617—92 STAT. 3133

§ 133 Gathering Information on Costs of Service.

(a) Information Required To Be Gathered.—Each electric utility shall periodically

gather information under such rules (promulgated by the Commission) as the Commission determines necessary to allow determination of the costs associated with providing electric service. For purposes of this section, and for purposes of any consideration and determination respecting the standard established by section 111(d)(2), such costs shall be separated, the maximum extent practicable, into the following components: customer cost component, demand cost component, and energy cost component. Rules under this subsection shall include requirements for the gathering of the following information with respect to each electric utility—

(1) the costs of serving each electric consumer class, including costs of serving different consumption patterns within such class, based on voltage level, time of use, and other appropriate factors;

(2) daily kilowatt demand load curves for all electric consumer classes combined representative of daily and seasonal differences in demand, and daily kilowatt demand load curves for each electric consumer class for which there is a separate rate, representative of daily and seasonal differences in demand;

(3) annual capital, operating, and maintenacnce costs—

(A) for transmission and distribution services, and

(B) for each type of generating unit; and

(4) costs of purchased power, including representative daily and seasonal differences in the amount of such costs.

Such rules shall provide that information required to be gathered under this section shall be presented in such categories and such detail as may be necessary to carry out the purpose of this section.

(b) COMMISSION RULES.—The Commission shall, within 180 days after the date of enactment of this Act, by rule, prescribe the methods, procedure, and format to be used by electric utilities in gathering the information described in this section. Such rules may provide for the exemption by the Commission of an electric utility or class of electric utilities from gathering all or part of such information, in such cases where such utility or utilities show and the Commission finds, after public notice and opportunity for the presentation of written data, views, and arguments, that gathering such information is not likely to carry out the purposes of this section. The Commission shall periodically review such findings and may revise such rules.

(c) FILING AND PUBLICATION.—Not later than two years after the date of enactment of this Act, and periodically, but not less frequently than every two years thereafter, each electric utility shall file with—

(1) the Commission, and

(2) any State regulatory authority which has ratemaking authority for such utility, the information gathered pursuant to this section and make such information available to the public in such form and manner as the Commission shall prescribe. In addition, at the time of application for, or proposal of, any rate increase, each electric utility shall make such information available to the public in such form and manner as the Commission shall prescribe. The two-year perod after the date of the enactment specified in this subsection may be extended by the Commission for a reasonable additional period in the case of any electric utility for good cause shown.

(d) ENFORCEMENT.—For purposes of enforcement, any violation of a requirement of this section shall be treated as a violation of a provision of the Energy Supply and Environmental Coordination Act of 1974 enforceable under section 12 of such Act (notwithstanding any expiration date in such Act) except that in applying the provisions of such section 12 any reference to the Federal Energy Administrator shall be treated as a reference to the Commission.

¶ 32,011 Transportation Certificates for Natural Gas

44 F. R. 17644 (March 22, 1979)

SUMMARY: The Economic Regulatory Administration (ERA) is publishing this proposed rule for action by the Federal Energy Regulatory Commission (the Commission), pursuant to section 403 of the Department of Energy Organization Act (DOE Act). The proposed rule would encourage and facilitate the issuance by the Commission of one year certificates of public convenience and necessity, including temporary certificates, under section 7(c)(1) of the Natural Gas Act, authorizing the transportation of natural gas purchased by end-users in order to displace fuel oil.

Pursuant to section 403(b) of the DOE Act, ERA is requiring the Commission to take final action on this proposed rule by May 17, 1979. The Commission will shortly announce by notice in the FEDERAL REGISTER the comment and public hearing procedures to be followed in connection with this rulemaking. Shortly, ERA will publish its own proposed rule establishing the procedures to be followed by the ERA Administrator for certification to the Commission of the use of natural gas for fuel oil displacement.

DATES: Commission to take final action by May 17, 1979. Dates for comments and public hearings to be determined later.

FOR FURTHER INFORMATION CONTACT:

Lynne H. Church, Division of Natural Gas Regulations, Economic Regulatory Administration, 2000 M Street, N.W., Room 3308, Washington, D.C. 20461, (202) 632-4721.

James G. Beste, Office of the General Counsel, Department of Energy, Room 7140, 12th & Pennsylvania Avenue, N.W., Washington, D.C. 20461, (202) 633-8788.

SUPPLEMENTARY INFORMATION:

I. Background.
II. Discussion of the Rule.
III. Procedures for Completion of Final Action.
IV. Environmental and Regulatory Analyses.

I. BACKGROUND

There is an urgent and immediate need to reduce the Nation's reliance on oil imports. The adverse effects of that reliance on the Nation's security of energy supplies, balance of payments, and domestic inflation rate require strong action. The recent tightening of world oil supplies and increases in international oil prices require that we give near term import reduction the highest priority.

Increased use of present supplies of natural gas is one of the most effective means of reducing oil consumption in the near term. Expanded use of gas will help the United States meet its commitments to reduce the demand for imported oil together with the other member nations of the International Energy Agency. It will also cushion any oil shortages, as well as soften the impact of imported oil prices on the Nation's balance of payments and inflation rate. This proposed rule is designed to meet that need, by encouraging and facilitating the filing of applications to transport oil displacement gas.

The Commission has already taken steps providing for the transportation of direct purchase gas. For example, the Commission's regulation implementing section 311(a)(1) of the Natural Gas Policy Act of 1978 (NGPA) (18 CFR 284.101 *et seq.*) authorizes the transportation of natural gas by interstate pipeline companies on behalf of intrastate pipeline and local distribution companies without prior Commission approval. Under that regulation an intrastate pipeline or a local distribution company selling gas directly to an end-user, or transporting gas for a producer who has sold to an end-user, may arrange for an interstate pipeline company to transport the gas on its behalf. In addition, Federal Power Commission Orders No. 533 and 533A and Federal Energy Regulatory Commission Order No. 2 provide for the issuance of certificates for the transportation by interstate pipeline companies of gas purchased directly from producers by high priority commercial

and industrial users. The Commission is currently considering a new direct purchase rule for certain high priority and essential agricultural users (Docket No. RM79-18).

None of those rules, however, provides a vehicle for lower curtailment priority industrial users or electric utilities to arrange for transportation by interstate pipeline companies of gas purchased directly from producers for fuel oil displacement. In addition, there may be circumstances where the tranportation by an interstate pipeline company of gas purchased directly by end-users from an intrastate pipeline or a local distribution company, or gas purchased from a producer who arranges for an intrastate pipeline or a local distribution company to distribute the gas, does not qualify under section 311(a)(1) of the NGPA. There may also be circumstances where the interstate pipeline company, although eligible, chooses not to use the section 311(a)(1) authority.

The rule we are proposing, therefore, fills a significant gap in existing natural gas regulations. By authorizing the issuance of transportation certificates by the Commission for oil displacement uses certified by the ERA Administrator, the proposed rule encourages and facilitates the movement of gas to users who are in a position to switch from fuel oil, but who otherwise would not have been able to take advantage of Commission regulations allowing transport of the gas. This proposal reflects a cooperative effort between the Commission and ERA to confront our national need to reduce reliance on oil imports. It follows the precedent set during the coal strike of 1978, where ERA issued guidelines for certifying electric utilities which were unable to obtain coal, but had the capacity to burn gas, or which could wheel power to coal shortage areas (43 F.R. 11748, March 21. 1978). The Commission issued a companion rule (18 CFR 157.42) allowing the issuance of limited transportation certificates for movement of natural gas to the ERA certified utilities.

This proposed rule, the text of which was sent to the Chairman of the Commission by Secretary of Energy Schlesinger (see attached letter) on March 13, 1979, would implement section 7(c)(1) of the Natural Gas Act (NGA). That section provides that natural gas companies must obtain a Commission certificate of public convenience and necessity for the interstate transportation of natural gas. Section 7(c)(1)(B) of the NGA establishes the procedural requirements for the Commission's consideration of certificate applications, and allows the Commission to issue temporary certificates without notice or hearing in certain circumstances, pending the final determination of the certificate application.

Section 403 of the DOE Act authorizes the Secretary of Energy to propose rules for Commission action regarding certain Commission functions, including it certificate functions under section 7 of the NGA, and to set a reasonable time limit for completion of Commission action. The Secretary's authority to propose rules under section 403 was delegated to the ERA Administrator by Department of Energy Delegation Order No. 0204-4 (42 FR 60726). This is the first time that DOE has exercised its authority under section 403.

II. Discussion of the Rule

Under this proposed rule, any interstate pipeline company may file an application with the Commission for a certificate to transport natural gas purchased by an "eligible user" from an "eligible seller" (§ 157.200). An "eligible users" would be any user who consumes gas for fuel oil displacement as certified by the ERA Administrator (section 157.202(e)). An "eligible seller" would be any willing seller, except an interstate pipeline company—to the extent that it would be selling gas committed or dedicated to interstate commerce on November 8, 1978, within the meaning of section 2(18) of the NGPA. The exclusion of certain sales by interstate pipeline companies could be waived by the Commission upon a showing of public interest. An application could include a request for a temporary transportation certificate which the Commission may issue without notice or hearing (§ 157.201(b)).

Under the proposed rule, applications for transportation certificates, including temporary certificates, could not be granted by the Commission unless the ERA Administrator had certified that the gas to be transported would displace fuel oil

(§ 157.204(a)). Transportation certificates could be issued for a period of up to one year (§ 157.204(b)) and renewed for an additional year upon reapplication (§ 157.204(c)). Transportation certificates would be effective only so long as consumption of the gas in question displaces fuel oil and the certificated interstate pipeline company operates in accordance with the order issuing the certificate, the NGA, and applicable Commission rules, regulations, and orders. For good cause shown, the Commission would be authorized to terminate a certificate at any time (§ 157.204(f)). Transportation rates shall be charged as provided in Part 284 of this chapter (§ 157.204(h)).

No participants in transactions contemplated by this rule, whether as buyers, sellers, or transporters of gas, should be penalized in any future curtailment proceeding as a result of such participation. Therefore, the natural gas transported under this proposed rule would not be considered as either a gas supply or market in the Commission's determination of an interstate pipeline company's requirements in any future curtailment proceeding (§ 157.205). In addition, in order to encourage maximum participation in this program, the Commission would not assert any jurisdiction over an intrastate pipeline or local distribution company participating in the sale or transportation of gas to an "eligible user," except as otherwise provided in this proposed rule (§ 157.206(a)).

This proposed rule should be read in conjunction with the proposed rule that ERA will issue shortly regarding its certification of the use of gas for fuel oil displacement Under the rule, any end-user that intends to purchase natural gas directly from an "eligible seller" to displace fuel oil could apply to the ERA Administrator for a certification of "eligible use." If the Administrator determined that a proposed purchase of gas is for an "eligible use," he would transmit his certification directly to the Commission with a copy to the applicant. This certification is a prerequisite to the granting by the Commission of a transportation certificate under this proposed rule.

III. Procedures for Completion of Final Action

Pursuant to section 403(b) of the DOE Act, ERA is requiring the Commission to take final action on this proposed rule by May 17, 1979. However, given the urgent need to reduce our reliance on oil imports, we urge the Commission to issue the proposed rule as an interim final rule, effective immediately, with provision for later modifications after consideration of public comments. If the Commission issues an interim final rule, we will likewise issue our rule on certification of eligible uses in final form immediately. The Commission will shortly announce, by notice in the Federal Register, the comment procedures to be followed in connection with this rulemaking.

IV. Environmental and Regulatory Analyses

Due to the urgent need to take immediate action to reduce the Nation's dependence on oil imports, this rule is being proposed prior to the completion by ERA and the Commission of an environmental analysis. Upon completion by ERA and the Commission of their review of this proposed rule pursuant to their responsibilities under the National Environmental Policy Act of 1969 (42 U.S.C. 4321, *et seq.*), the two agencies will publish their findings in the Federal Register.

Because the Commission is the agency which will take final action on this proposed rulemaking, a regulatory analysis within the meaning of DOE Directive Order 2030, December 18, 1978, implementing Executive Order No. 12044 on improving government regulations, has not been prepared by ERA. Furthermore, we are currently evaluating whether a regulatory analysis is required for our own rule on certification of eligible uses, and, if so, it would encompass the scope of this proposed rule as well as that of our certification rule.

(Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565 (42 U.S.C. 7101). Department of Energy Delegation Order No. 0204-4 (42 FR 60726).)

In consideration of the foregoing, it is proposed to amend Part 157 of Chapter I of Title 18, Code of Federal Regulations, by adding a new Subchapter F, as set forth below.

Issued in Washington, D.C., March 18, 1979.

SUBCHAPTER F—TRANSPORTATION CERTIFICATES FOR FUEL OIL DISPLACEMENT GAS UNDER SECTION 7(c) OF THE NATURAL GAS ACT

Sec.
157.200 Applicability.
157.201 General rule.
157.202 Definitions.
157.203 Application requirements.
157.204 General conditions.
157.205 Treatment of this gas in curtailment plans.
157.206 Special conditions.

AUTHORITY: Depatment of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565 (42 U.S.C. 7101). Department of Energy Delegation Order No. 0204-4 (42 FR 60726).

SUBCHAPTER F—TRANSPORTATION CERTIFICATES FOR FUEL OIL DISPLACEMENT GAS UNDER SECTION 7(c) OF THE NATURAL GAS ACT

§ 157.200 Applicability.

This subpart implements section 7(c)(1) of the Natural Gas Act to provide for the issuance of certificates of public convenience and necessity authorizing the transportation of natural gas purchased directly from eligible sellers by eligible end-users in order to displace fuel oil.

§ 157.201 General rule.

(a) *Applications.* Any interstate pipeline company may file an application as described in § 157.203 for a certificate to transport natural gas purchased by an eligible end-user from an eligible seller.

(b) *Temporary certificates.* An application may include a request for a temporary transportation certificate. Any request for a temporary certificate shall be processed pursuant to section 7(c)(1)(b) of the Natrual Gas Act. The Commission may issue the temporary certificate without notice or hearing.

(1) If the application for a temporary transportation certificate is sufficient on its face, a temporary certificate may be issued by the Director of the Office of Pipeline and Producer Regulation pursuant to his authority under § 3.5(f)(1)(iv) of this chapter.

(2) The interstate pipeline company may, within 15 days of the date of issuance, file in writing its acceptance or rejection of the temporary certificate. If no acceptance or rejection has been filed within the 15 days, the temporary certificate shall be deemed to have been accepted. Such temporary certificate shall be effective (a) on the date the Commission received acceptance, or (b) on the fifteenth day after issuance if no acceptance or rejection is filed within the 15 days, or (c) on such other date as may be prescribed by the Commission.

§ 157.202 Definitions.

For the purposes of this subpart, the terms:

(a) "Administrator" means the Administrator of the Economic Regulatory Administration;

(b) "Certificate" means any certificate of public convenience and necessary for tranportation issued under this subpart;

(c) "Eligible seller" means any willing seller of natural gas, except an interstate pipeline company to the extent that the natural gas sold by the interstate pipeline company was committed or dedicated, as defined in section 2(18) of the Natural Gas Policy Act of 1978, on November 8, 1978;

(d) "Eligible use" means any use of natural gas certified by the Administrator to be us for fuel oil displacement pursuant to the ERA special rule for certification of eligible use of natural gas to displace fuel oil;

(e) "Eligible user" means any person who consumes natural gas for an eligible use.

§ 157.203 Application requirements.

All applications for transportation certification pursuant to this subpart shall:

(a) Indicate the total volume of natural gas to be transported under the proposed certificate and estimated peak day and average day volumes;

(b) Include a statement by the interstate pipeline company that it is has capacity sufficient to perform the transportation service without detriment or disadvantage to any existing customers;

(c) Provide a copy of the proposed transportation agreement and the proposed transportation rate, together with a breakdown and justification of the proposed rate level to the extent indicated in § 284.106 of this chapter for interstate pipeline companies or

§ 284.126 of this chapter for intrastate pipeline companies;

(d) Include a statement by any local distribution company participating in the transportation of the gas to the end-use that it has capacity sufficient to perform the transportation service without detriment or disadvantage to its other customers;

(e) Provide a copy of the gas purchase contract with the eligible seller underlying the proposed transportation;

(f) Provide a certified copy, if one has been obtained, of any currently effective determination by a jurisdictional agency under section 503 of the Natural Gas Policy Act of 1978 and Part 274 of this chapter applicable to the natural gas to be transported;

(g) Describe any facilities that will be constructed in order to provide the services, as well as any other facilities that will be utilized, and specify their location. For purposes of this paragraph, there is no requirement that omission of other filing requirements be justified. For purposes of this paragraph, the following provisions are waived:

(1) 18 CFR 157.13—Form of exhibits to be attached to applications;

(2) 18 CFR 157.14—Exhibits

(3) 18 CFR Part 159—Fees and annual charges under the Natural Gas Act;

(4) 18 CFR Part 201—Uniform system of accounts for natural gas companies; and

(5) 18 CFR Part 260—Statements and reports (schedules);

(h) If an intermediary particpates in the transaction between the eligible end-user and the eligible seller and charges a fee, indicate the amount of the fee and terms of payment and the intermediary's affiliation, if any, with the eligible seller or the interstate pipeline company;

(i) If either the eligible seller or the eligible end-user assumes the cost of the construction of any gathering facilities in order to consummate the purchase, provide the cost, terms of payment, ownership, and date of construction of the facilities; and

(j) Provide, as soon as available, a copy of the certification of eligible use issued by the Administrator.

§ 157.204 General conditions.

(a) *Certification of eligible use by the Administrator.* Applications for transportation certificates, including temporary certificates, under this subpart shall not be granted by the Commission unless the Administrator pursuant to ERA's special rule for certification of eligible use of natural gas to displace fuel oil has certified that consumption of the natural gas proposed to be transported is an eligible use.

(b) *Term.* Transportation certificates under this subpart may be issued for a term of up to 1 year.

(c) *Renewal.* Transportation certificates issued under this subpart may be renewed for an additional year upon reapplication within 60 days of their expiration. The application for renewal shall include à recertification of eligible use by the Administrator.

(d) *Extension of term for take-or-pay users.* If an eligible end-user is unable to receive natural gas supplies for which it has paid under a take-or-pay provision in the underlying sales contract, the transporting interstate pipeline companies may file a request for a 90 day extension of the certificate authorization. The request shall include a statement of the undelivered volumes and the time necessary to complete delivery thereof. Upon receipt of a letter from the Secretary of the Commission acknowledging a filing for such purposes, the requested extension shall be deemed approved.

(e) *Acceptance of certificate.* The certificate shall be void and without force or effect unless accepted in writing by the interstate pipeline company within 15 days from the issue date of the order issuing such certificate.

(f) *Termination.* The transportation certificate issued to the interstate pipeline company is not transferrable in any manner and shall be effective only so long as the natural gas is consumed for elegible use and the interstate pipeline company continues the operations authorized by the order issuing such certificate and in accordance with the provisions of the Natural Gas Act, as well as the applicable rules, regulations, and orders of the Commission. The Commission may, for good cause shown, terminate the certificate at any time.

(g) *Supplemental filing.* The eligible end-user shall file a report with both the Commission and the Administrator withn 60 days of the termination or expiration of the certificate, containing:

(1) The total amount of natural gas consumed during the term of the certificate,

(2) The actual monthly volume in barrels of each type of fuel oil displaced during the term of the certificate,

(3) The average delivered cost per Mcf paid, itemized by amounts paid to:

(i) The producer,

(ii) Each pipeline company and distributor involved in transporting the natural gas, and

(iii) Any other parties, and

(4) The volumes of each type of fuel oil displaced which have been retained in the end-users inventory or otherwise remain at the end-user's disposal.

(h) *Rates and charges.* The rates for transportation by any interstate or intrastate pipeline companies will be charged in accordance with Part 284 of this chapter.

§ 157.205 Treatment of this gas in curtailment plans.

All volumes of natural gas purchased from an eligible seller for an eligible use and transported by an interstate pipeline company pursuant to a transportation certificate granted under this subpart shall not be considered as either a gas supply or market in a determination of an interstate pipeline company's customer's requirements for present or future allocations of natural gas during periods of natural gas curtailment.

§ 157.206 Special conditions.

(a) The Commission shall not assert any jurisdiction, except to the extent provided in this subpart, over any intrastate pipeline or local distribution company which participates in the sale or transportation to an eligible user of natural gas transported pursuant to this subpart; and

(b) The Commmission may waive the § 157.202(c) exclusion of sales of certain natural gas by interstate pipeline companies upon a showing the waiver is in the public interest.

Department of Energy

Washington, D.C.

MARCH 13, 1979.

DEAR MR. CURTIS: I am enclosing for the information of the Federal Energy Regulatory Commission, a rule which the Department of Energy will shortly propose pursuant to Section 403 of the Department of Energy Organization Act. The rule will facilitate and encourage the transportation by interstate pipeline companies of natural gas purchased directly by end-users for the displacement of fuel oil.

There is an urgent national need to reduce our demand for oil imports immediately. As I stated in my February 27, 1979, letters to you and the other commissioner, "[t]he detrimental effect of such imports on our security and balance of payments is reason enough to take firm action." The recent tightening of world oil supplies and increases in international oil prices, partly flowing form the political development in Iran, make it essential that near-term import reduction be given the highest priority.

The increased use of present supplies of natural gas is potentially one of the most effective means of reducing oil consumption in the near term. Use of this gas will be important in helping the U.S. meet its commitment to reduce the demand for imported oil together with the other member nations of the International Energy Agency. An expanded use of gas will not only lessen the need for oil imports and cushion any oil shortages, but will also mitigate the impact of ever increasing foreign oil prices on the nationa's balance of payments and the domestic inflation rate. While we encourage increasing general system supply of interstate pipeline companies, we recognize that facilitating the transportation of direct purchase gas to end-users who are able to displace fuel oil would optimize the gas use.

The Commission already has in place regulations which provide for the transportation of direct purchase gas. For example, section 311(a) of the Natural Gas Policy Act of 1978, and the Commission's implementing regulation, permit the transportation of natural gas by interstate pipelines and

local distribution companies, without prior Commission approval. This provides a vehicle whereby an intrastate pipeline company, including a so-called Hinshaw Pipeline, or a local distribution company selling gas directly to an end-user, or, transporting gas for a producer, may arrange to have an interstate pipeline company transport the gas on its behalf. Additionally, high priority industrial users may take advantage of the Federal Power Commission Orders No. 533, 533A and the Federal Energy Regulatory Commission Order No. 2, which allow the issuance of certificates for the transportation by interstate pipeline companies of gas purchased directly from producers. The Commission currently is considering a similar direct purchase rule for high priority and essential agricultural users, as defined in the NGPA.

None of these final or proposed rules, however, would provide a means for users, such as lower curtailment priority industrial companies or electric utilities who may now be in a position to displace large quantities of fuel oil, to arrange for transportation by interstate pipeling companies of gas purchased directly from producers. Moreover, there may be certain situations in which the transportation by an interstate pipeline company of gas purchased directly from an intrastate pipeline or a local distribution company or gas which a local distribution company is transporting for a producer may not qualify under section 311(a) of the NGPA, or the pipeline company elects not to used that authority. Hence, the rule we are proposing fills a gap in existing natural gas regulations.

Under this proposed rule, any interstate pipeline may file with the Commission, under section 7(c) of the Natural Gas Act, an application for a one-year certificate to transport gas purchased by an "eligible end-user" from an "eligible seller." An "eligible end-user" would be anyone who consumes gas for a use certified by the Economic Regulatory Administration to displace fuel oil. An "eligible seller" would be any willing seller, including, among others, producers and any local distribution companies and intrastate or interstate pipeline companies not using the section 311(a) vehicle. However, an interstate pipeling company would not quality as an "eligible seller" if the natural gas it proposed to resell to the end-user was committed or dedicated on November 8, 1978, within the meaning of section 2(18) of the NGPA.

Within the next several days, we intend to publish in the FEDERAL REGISTER the proposed rule and prescribe a date upon which the Commission must complete final action on the proposal, as provided in section 403(b) of the DOE Act.

However, given the urgent need described above to reduce our demand for imported oil, we urge the Commission to issue the proposed rule as an interim final rule, effective immediately, with provision for later modifications after consideration of public comments.

Concurrently, ERA will promulgate a special rule which establishes the procedures for ERA certification that the usage of natural gas will displace fuel oil and otherwise to be "eligible use." The ERA certification is intended to assist the Commission in expediting its review of certificate applications. If the Commission issues an interim final rule, ERA will likewise issue its special rule in final form immediately, since the current oil situation is one which is "likely to cause serious harm or injury to the public health, safety, or welfare" as that term is used in Section 501(e) of the DOE Act.

Sincerely,

JAMES R. SCHLESINGER,
Secretary.

Honorable Charles B. Curtis,
Chairman, Federal Energy Regulatory Commission,
825 North Capitol Street, N.E.,
Washington, D.C. 20426.

¶ 32,012 Refund Requirements for Oil Pipelines

44 F. R. 18046 (March 26, 1979)

[Docket No. RM 77-22]

REGULATIONS UNDER THE FEDERAL POWER AND NATURAL GAS ACTS AND THE NATURAL GAS POLICY ACT OF 1978; REFUND REQUIREMENTS FOR OIL PIPELINES

Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission gives notice of a proposed rulemaking which would (1) tie the rate of interest required on refunds to the prime rate charged by commercial banks for short-term business loans, (2) apply the rate of interest to the rate for computation of carrying charges on amounts accumulated in the deferred purchased gas cost account, (3) compound monthly the rate of interest on refunds, (4) impose refund obligations on oil pipelines, and (5) reduce the number of reports that must be filed under 18 CFR §§ 35.19a and 154.67; and request comments thereon.

DATE: Written comments by April 23, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N. E., Washington, D.C. 20426 (Reference Docket No. RM 77-22).

FOR FURTHER INFORMATION CONTACT:

Dennis Melvin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4891.

Teresa Ponder, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4236.

NOTICE OF PROPOSED RULEMAKING

Before Commissioners: Rate of Interest on Amounts Held Subject to Refund.

Notice is hereby given, that the Federal Energy Regulatory Commission [1] proposes to amend §§ 35.19a, 154.67, 154.102, 154.38(d)(4)(iv)(C), and 273.302(e)(i) of Chapter I. Title 18, of the Code of Federal Regulations (CFR), and add a new Chapter XV, Part 1605 Title 49, CFR. The amendments would work to tie the interest rate on carrying charges and refunds to the prime interest rate charged by commercial banks for short term business loans, require monthly compounding of interest on funds held subject to refund, impose definitive refund obligations on oil pipelines, and reduce the number of reports that must be filed under §§ 35.19a and 154.67 of the Regulations.

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), 42 U.S.C. § 7101, *et seq.* (1977), and Executive Order No. 12009, 42 FR 46267 (1977), the functions and responsibilities of the Interstate Commerce Commission (ICC) pertaining to the transportation of crude and refined petroleum and petroleum byproducts, derivatives, and petrochemicals by pipeline were transferred to the Secretary of Energy and the Commission. Section 402(b) of the DOE Act provides that all functions and authority of the ICC relating to the establishment of rates and charges for the transportation of oil by pipeline, or the valuation of oil pipelines, is vested in the Commission. Included in this transfer of functions and responsibilities is the authority to compel refunds with interest, of unjustified rates or charges for such transportation, as required in the Interstate Commerce Act, 49 U.S.C. 15(7) (1940). The "savings provisions" of section 705(a) of the DOE Act provide, among other things, that rules and regulations relating to func-

[1] The term "Commission", when used in the body of this notice, shall refer to the Federal Power Commission with respect to actions taken before October 1, 1977, and shall refer to the Federal Energy Regulatory Commission with respect to actions taken at any time subsequent to October 1, 1977.

tions transferred to the Commission, and all orders which are in effect at the time that the DOE Act takes effect shall continue in effect until modified, terminated, suspended, set aside or revoked by the Commission. Similarly, section 705(b) indicates that orders in pending proceedings shall continue in effect until modified, terminated, superseded, or revoked by the Commission, so long as any such discontinuance or modification is made under the same terms and conditions and to the same extent, as could have been accomplished had the DOE Act not been enacted.[2] Pursuant to the aforementioned authority, notice is hereby given that the decisions and policies formulated during the course of this proceeding, with certain exceptions, will be incorporated into Title 49 CFR under a new Chapter XV and Part 1605. The principles, if adopted, will be made applicable to all pending and future petroleum pipeline proceedings within our jurisdiction from the first day of the first month beginning after the effective date of the issuance of a final order in this docket.[3]

Historical Background

All refund rates were determined by the Federal Power Commission on a case-by-case basis until 1959. In 1959, a simple six percent per annum rate was established for refunds owed by independent natural gas producers.[4] The refund interest rate for electric utilities and regulated pipelines continued to be established on a case-by-case basis. In March, 1960, the Commission raised the interest rate on refunds for independent producers to seven per cent.[5]

Eight years later, the Commission ordered the rate of interest on refunds to be compounded monthly.[6] That order, however, was set aside before its implementation by the United States Court of Appeals because the procedure followed in adopting the rulemaking violated the notice requirements of the Administrative Procedure Act.[7] In setting aside the order, the Court emphasized that its decision addressed only procedural issues, not the merits of compounding interest. The decision left the Commission free to adopt another order requiring the compounding of interest on refunds, provided it followed the correct administrative procedure; however, the Commission did not do so in its subsequent order on refund interest rate.[8]

In 1971, the Commission began applying the seven percent simple interest rate to all refunds authorized under both the Federal Power Act and the Natural Gas Act.[9] At that time, the Commission considered but declined to adopt a proposal to tie the refund interest rate to the prime interest rate.

In 1974, the Commission ordered the refund interest rate raised to nine percent for all rate filings submitted on or after October 10, 1974.[10] The Court of Appeals for the District of Columbia remanded the order, stating that it was improper to limit the nine percent refund interest rate to filings which took place on or after October 10, 1974, and retain the seven percent interest rates for rate filings made before that date.[11] Subsequent to the Court's decision, the Commission issued a series of orders to amend and clarify its refund regulations, consistent with the Court's opinion.[12]

On June 24, 1977, nineteen public utility companies[13] jointly filed a Motion to Initiate a Rulemaking to Adjust Downward from nine percent

[2] Order No. 1, Docket No. RM 78-1, issued October 6, 1977.

[3] We note that "all pending" proceedings is intended to include, *inter alia*, *Trans-Alaska Pipeline System*, Docket No. OR 78-1.

[4] Order No. 215, 22 F. P. C. 668 (1959).

[5] Order No. 215-A, 23 F. P. C. 474 (1960).

[6] Order No. 362, 39 F.P.C. 412 (1968).

[7] *Texaco, Inc.* v. *F.P.C.* 668 (1959).

[8] Order No. 405, 43 F.P.C. 794 (1970).

[9] Order No. 442, 46 F.P.C. 1287 (1971).

[10] Order No. 513, 52 F.P.C. 920 (1974).

[11] *American Public Gas* v. *F.P.C.* 546 F.2d 983 (D.C. Cir. 1974).

[12] Order No. 513-A, Docket No. RM 74-18, issued July 14, 1976; Order Granting Rehearing of Order No. 513-A for Purposes of Further Consideration, Docket No. RM 74-18, issued August 19, 1976; Order Clarifying and Amending Order No. 513-A and Denying Rehearing, Docket No. RM 74-18, issued October 15, 1976; Order Denying Rehearing and Further Clarifying Order No. 513-A, Docket No. RM 74-18, December 6, 1976.

[13] Arizona Public Service Company, Arkansas Power & Light Co., Boston Edison Co., Carolina Power & Light Co., Central Vermont Public Service Corp., Florida Power & Light Co., Florida Power Corp., Louisiana Power & Light Co., Minnesota Power & Light Co., Mississippi Power & Light Co., Public Service Co. of Indiana, South Carolina Electric & Gas Company, Upper Peninsula Power Co., Utah Power & Light Co., Wisconsin Electric Power Co., Wisconsin Michigan Power Co., Alabama Power Co., Montaup Electric Co., Northern States Power Corp.

to seven percent the interest rate applicable to refunds under the Federal Power Act and the Natural Gas Act. On September 16, 1977, the Commission issued a Notice of Motion to Initiate Rulemaking to Adjust Interest Rate on Refunds, and requested that all interested parties file comments or petitions to intervene by October 1, 1977.[14] Numerous comments and petitions to intervene in the proposed rulemaking proceeding were received from various parties including electric, gas pipeline, and oil companies, and municipal and cooperative public power systems.[15]

SCOPE OF PROCEEDING

Section 154.67(c) of Title 18 CFR requires all regulated natural gas pipelines to make refunds at an interest rate of nine percent for those portions of rate filings which are placed in effect after suspension but which are determined by the Commission to be unjust and unreasonable pursuant to the Commission's authority under section 4(e) of the Natural Gas Act. Similarly, § 154.102(c) requires independent natural gas producers to make refunds to their customers at a rate of nine percent for those portions of rate filings which have been placed into effect subsequent to suspension but which have been determined by the Commission to be unjust and unreasonable. Interim regulation § 273.302(e)(1), implemented in accordance with the Natural Gas Policy Act, also requires a nine percent rate of interest on refunds made by natural gas producers in accordance with that Act. Section 273.302(e)(1) will not be separately discussed but will simply be revised to reflect the interest rate set forth in § 154.102(c). Section 35.19(a) requires a nine percent interest rate on refunds made by electric utilities.

With respect to oil pipelines, nothing in either the regulation governing oil pipeline proceedings before the ICC (*generally*, 49 CFR, Chapter 10), nor in the provisions of the Interstate Commerce Act (49 U.S.C. 15(7)), specifies a method of accounting for refundable monies, or a particular rate of interest applicable to refunds made by oil pipelines.[16]

Upon consideration of the comments submitted in response to the Notice of Motion to Initiate Rulemaking, and after a review of the Commission's current policies and practices with respect to interest rates on refunds, we have determined to expand the scope of this proceeding to encompass: (a) the appropriateness of using the prime rate charged by commerical banks for short-term business loans as the standard for setting refund interest rates, (b) compounding interest on refunds, (c) a mechanism for making automatic adjustments to the rate of interest required on refunds, (d) promulgation of a complete set of refund regulations related to oil pipelines, (e) carrying charges on the amounts accumulated in the deferred purchase gas cost account, and (f) a proposed reduction in the number of refund report filings for natural gas pipelines and electric

[14] On January 26, 1979, the Indiana Municipal Electric Association and several Cities (IMEA Cities) listed in Appendix B filed a motion in Docket No. RM 79-17 to raise the interest rate on refunds ". . . (1) to 12% (2) to 2 percentage points above the current prime rate; or (3) to the equity return requested in connection with the applicable company filing or, if that is not applicable, to that allowed in the Company's last rate case or settlement". In view of the fact that the issues raised by IMEA Cities are the subject of the instant rulemaking proceeding in Docket No. RM 77-22, the Commission shall terminate Docket No. RM 79-17 without prejudice, of course, to IMEA Cities to file comments in Docket No. RM 77-22.

[15] Appendix A. In addition to a petition to intervene filed in this Docket on October 3, 1977, the American Public Power Association (APPA) moved on February 5, 1979, that the refund rate should be made equal to the prime rate, plus one. Opposition to the motion was filed by the Arizona Public Service Company, *et al.* (APSC) on February 21, 1979, and a statement in support of the motion was filed by APPA on February 28, 1979. In view of the fact that we have broadened the scope of the issues in this rulemaking to include those raised by APPA, we will consider the arguments of APPA and APSC during the course of our deliberations in this docket.

[16] We expect, at some future time, to promulgate a complete statement of our own rules and regulations with respect to oil pipeline proceedings. At that time, the refund policies and requirements developed pursuant to this rulemaking will be incorporated therein. As indicated above, however, we will add a new provision at 49 CFR § 1605.95; included in a new Chapter XV, as an interim measure so that the application of these policies and requirements may begin immediately for oil pipelines within the Commission's jurisdiction.

utilities.[17] The appropriateness of the current rate of interest on refunds will be examined in this rulemaking proceeding in the context of these questions.

Discussion

A. Appropriate Standard for Refund Interest Rates

In general, there appear to be three primary considerations relevant to the determination of an appropriate standard for the interest rate(s) on refunds. First, the interest rate should provide just compensation to those who are required to pay rates that are later determined by the Commission to be excessive. Their losses, or costs, can be of three types: (a) opportunity losses of income that could have been earned by investing the "excess" funds elsewhere during the time the interim rates were in effect, (b) losses from an involuntary sacrifice or postponement in consumption while higher rates were being charged, and (c) opportunity losses of savings that might otherwise have been realized during the interim period through reduced borrowing.

Second, during the period in which proposed rate increases are in effect subject to refund, filing companies have the use of all refundable monies collected, subject to minor restrictions. The interest rate should reflect the benefits which are available to companies as a result of having the use of these funds. Such uses may include investments or using the funds as a substitute for short-term financing.

Finally, the interest rate on refunds should not provide incentives for filing companies to inflate rate requests or for any party to unnecessarily prolong the ratemaking process. If the rate of interest is too low, filing companies may find it in their interest to inflate rate increase requests or to prolong litigation as a means of obtaining low cost monies. On the other hand, an unreasonably high rate of interest may give customers an incentive to prolong litigation in order to maximize the return when refunds are finally ordered.

The Commission recognizes that the money market interest rates that reflect the costs saved by companies which have temporary use of excess revenues, are not necessarily identical with the costs incurred by customers who pay the excess revenues. The Commission believes, however, that the consideration most relevant to any decision on the proper interest rate on refunds is that the sellers should not profit from the availability of excess revenues.

We believe it is appropriate to tie the interest rate on refunds to the prime rate charged by commercial banks for short-term business loans. It is true that many companies filing with this Commission are not eligible for the prime rate. Moreover, the requirement for "compensating balances" raises the effective borrowing cost above the nominal interest rate. On the other hand, it is also true that the availability of funds subject to refund does not always replace short-term bank borrowing, and in some situations the funds might be used for purposes that earn less than the prime rate.

We have determined that use of the prime rate, as set forth in more detail in Section C of this Notice, in setting the interest rate on refunds offers an acceptable compromise of these considerations. We also believe that use of the prime rate will be equitable to customers who are burdened by paying excess rates. In some cases this burden is quickly passed forward to residential, commercial, and industrial customers, but in other cases it is absorbed, at least temporarily, by the wholesale customer. Commercial and industrial costomers, in turn, may or may not raise their selling prices to pass on the higher rates. In the presence of these uncertainties as to the actual costs borne by customers, we believe that the best course is to settle on a generally accepted money market indicator, such as the prime interest

[17] Another issue alluded to in the comments deals with the notion of a premium interest rate provision for inflated rate filings. This provision would apply when the revenues collected significantly exceed the subsequently allowed amount. This is a matter that can logically be separated from the issues listed above, and we feel it is advisable to do so. Consequently, consideration of a premium interest rate on refunds provision will be deferred until a later time.

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rate charged by commercial banks for short-term loans. However, the Commission also solicits comments as to whether a premium, or a fixed percentage, should be added to the prime rate in determining the appropriate rate of interest for refunds, and if so, what the basis of the premium should be.

B. COMPOUNDING OF INTEREST ON REFUNDS

Adjustment of the interest rate on refundable amounts has not occurred since 1974.[18] At that time the Commission set the interest rate at nine percent. That order and every order preceding it, with the exception of Order No. 362, 39 F.P.C. 412 (1968) provided that the interest should be calculated on a simple annual basis.[19]

In Order No. 362, *supra*, at 412, the Commission determined that the underlying purpose of requiring interest on refundable revenues would be better served if the interest payments on such amounts represented compound rather than simple interest:

> When simple interest is imposed, the company receives an interest-free loan of the accumulated interest on all funds which are advanced by its customers and later ordered to be returned to them. The value of this interest-free loan mounts with the duration of the period in which the increased rates are in effect subject to refund.

Because utilities typically bill and receive payments on a monthly basis, the Commission decided on Order No. 362 to require the compounding of interest on monthly basis.

As noted above, Order No. 362 was set aside on procedural grounds in *Texaco, Inc.* v. *Federal Power Commission, supra.* The Court explicitly noted that its decision had not been based on the merits of the rule, but rather on procedural issues only. The Commission could at that time have re-instituted a rulemaking to require the compounding of interest rates. The succeeding order on this issue, however, adopted the previous policy of requiring simple interest on refunds.[20] The Commission concluded, without further explanation, that reconsideration of "other relevent facts" indicated that it would not be in the public interest to impose a compound interest requirement. *Id.* at 795.

When a company is required to make refunds, it enjoys the use of the principal *and* accumulated interest on that principal until it makes the refund. Payment of simple interest on the refund does not require the refunding company to reimburse the customer for the use of the accumulated interest. In the Commission's view, therefore, the use of simple interest for amounts to be refunded may not compensate the customer fully for the use of his money collected during the rate proceeding. As the Commission noted in Order 362, unless a company is charged for the use of interest accumulated on principal as well as for the use of the principal itself, it will have the equivalent of an interest-free loan in the amount of such accumulated interest. Clearly, the longer the delay in refunding the principal plus interest, the higher will be the value of the interest-free loan of such accumulated interest.

The Commission believes that the period for compounding interest should reflect the frequency with which payments of the proposed rates (including any overcharges) are received. For purposes of this rulemaking, compounding on a monthly basis would best reflect billing cycles in the industry.

The effect of requiring the computation of interest on a compound basis will be to provide for a refund which more adequately compensates the purchaser for the use of his money. Such a procedure should reduce the unwarranted benefits described above, particularly in those rate proceedings that continue for several years beyond the effective date of the proposed rates. The result will also reduce any incentive to delay the resolution of rate cases.

By including in this notice of proposed rulemaking a requirement for compound interest, the Commission solicits the comments and suggestions of interested parties on this point. Specific areas for discussion should in-

[18] Order No. 513, *supra* note 11 at 5.

[19] Order No. 215, 22 FPC 668 (1959); Order No. 215-A, 23 FPC 474 (1960); Order No. 405, 43 FPC 794 (1970); Order No. 442, 46 FPC 1286 (1971).

[20] Order No. 405, *supra* note 7, at 4.

clude, but are not limited to: (1) the recommended frequency of compounding and (2) any administrative and computational difficulties associated with making refund calculations on a compound basis.

C. AUTOMATIC ADJUSTMENT OF THE RATE OF INTEREST ON REFUNDS

It is generally accepted that the rate of interest on refunds deemed appropriate at the time the rate was established may not be appropriate in the ensuing months or years due to changed economic or financial market conditions. The Commission has recognized this and expressed a commitment to periodically re-assess the reasonableness of the interest rate.[21]

In furtherance of this objective, the Commission would like to shift from the current practice of using rulemaking procedures to set interest rates on refunds, to a simpler, more predictable, process. Mechanisms for automatic adjustments based on changed economic conditions have been approved thus far in two other jurisdictional accounting areas.[22] There is reason to believe that such a mechanism can be employed in establishing the proper interest rate applicable to amounts subject to refund.

The Commission proposes to adopt a policy of announcing the interest rate on refunds not later than the last day of each calendar quarter for application to amounts subject to refund during the following calendar quarter. The interest rate will be based on the average prime rate charged by commercial banks on short-term business loans, rounded upward or downward, as applicable, to the nearest half of a percentage point. The average prime rate will be the average for the most recent three full months reported in the *Federal Reserve Bulletin*.[23]

The Commission believes that a shift to an automatic mechanism for adjusting the interest rate on refunds in accordance with changes in the prime rate will substantially reduce the time and expense devoted to keeping the interest rate current with financial market developments. The automatic mechanism should yield interest rates that achieve the Commission's regulatory objectives and are equitable to all interested parties.

Comments and suggestions concerning the proposed automatic adjustment mechanism are invited.

D. REFUND REQUIREMENTS FOR OIL PIPELINES

Section 15(7) of the Interstate Commerce Act provides that the Commission may require refunds with interest of those portions of rates or charges found not justified. This section also provides that the Commission may require a carrier to keep accurate account in detail of all amounts received by reason of a suspended rate, specifying by whom and in whose behalf such amounts are paid. As noted herein at page six, however, there are no regulations governing refunds to be made by oil pipelines. The Commission believes that regulations should be promulgated in order to eliminate any uncertainty from pending and future oil pipeline rate proceedings.

In view of the similarity with regard to refunds between section 15(7) of the Interstate Commerce Act, and section 4(e) of the Natural Gas Act, we believe it is appropriate to promulgate regulations governing refunds by oil pipelines similar to those governing refunds by natural gas pipelines. We therefore propose that 49 CFR 1605.95 reflect oil pipeline refund requirements essentially identical to those recommended in 18 CFR 154.67[24]. The Commission perceives no reason to distinguish between the rate of interest or refund methodology applicable to oil pipelines, and that which applies to natural gas pipelines. Comments and suggestions on the proposed regulation are invited.

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[21] Order No. 513, *supra*, at 923.

[22] Order No. 550, Docket No. RM76-1 issued June 24, 1976 (specified reasonable rate of return to be provided in hydroelectric project licenses); Order No. 561, Docket No. RM75-27, issued February 2, 1977 (determination of rate for computing AFUDC).

[23] For example, see Table 1.34, *Federal Reserve Bulletin*, December 1978, page A26, showing the average prime rates by months through November 1978.

[24] Inasmuch as section 15(7) contains no language requiring a motion to place suspended rates into effect, as does section 4(e), that requirement is not included in the proposed 49 C.F.R. § 1605.95. Moreover, we are not proposing to require either monthly or annual refund reports from oil pipelines.

E. CARRYING CHARGES ON AMOUNTS ACCUMULATED IN THE DEFERRED PURCHASED GAS ACCOUNT

The Commission proposes to change the carrying charge rate accrued on positive and negative balances in the unrecovered purchased gas account (Account 191) to that proposed for refunds held by pipelines. The proposed change assumes that the same factors which support the general interest rate also support the change in the carrying charge rate for amounts accumulated in Account 191. Comments are invited on whether there should be a distinction between the refund rate and the rate for deferred purchased gas accounts.

F. PROPOSED REDUCTION IN THE NUMBER OF REFUND REPORT FILINGS FOR NATURAL GAS PIPELINES AND ELECTRIC UTILITIES

Currently, § 154.67 of the Regulations which governs refunds for natural gas pipelnes, and § 35.19a of the Regulations which governs refunds for electric utilities, require the submission of monthly refund reports. While it is clear that this is information useful in monitoring the amouts collected subject to refund and is also useful to our staff and others in certain instances in evaluating the utility's proposed rate increase, the Commission is not persuaded that these reports should be filed monthly by the affected utilities in all cases.

Accordingly, the Commission is proposing to require annual refund reports showing monthly computations. This is subject, however, to the condition that the utility shall be required to submit reports more frequently in individual cases if directed to do so by the Director of the Office of Pipeline and Producer Regulation or the Director of the Office of Electric Power Regulation, as appropriate. The annual reports shall be submitted on or before March 31 of each year and shall cover the previous calendar year or portion of the calendar year, as applicable, that the proposed rates were in effect subject to refund.

There are additional amendments included in this notice which are strictly drafting changes and are not intended to change the operations of those sections. If any amendment inadvertently changes the meaning or operation of the sections, comments to that effect are invited.

COMMENT PROCEDURE

Any interested person, including Commission staff, may submit to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, not later than April 23, 1979, data, views and comments in writing concerning the matters herein proposed. An original and 14 conformed copies should be filed with the Commission, and should reply to Docket Number RM77-22. Submissions to the Commission should indicate the name and address of the person to whom correspondence in regard to the proposal should be addressed. Written submittals will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. The Commission will consider all written submissions made before acting on the matters herein proposed. The Secretary shall cause prompt publication of this notice to be made to the FEDERAL REGISTER.

Docket No. RM79-17 is terminated for the reasons set forth earlier in this notice without prejudict to IMEA Cities filing comments in response to the instant notice of proposed rulemaking in Docket No. RM77-22.

(Administrative Procedure Act, 5 U.S.C. 551; Sec. 16, Natural Gas Act, 15 U.S.C. 7170; Sec. 309, Federal Power Act, 16 U.S.C. 825h; Sec. 17(3) of the Interstate Commerce Act, 49 U.S.C.17(3) Department of Energy Organization Act, P.L. 95-91, E.O. 12009, 42 F.R. 46267.)

In consideration of the foregoing the Commission proposes to amend Parts 35, 154, and 273 of Chapter 1, Title 18, and Chapter XV, Part 1605, Title 49, Code of Federal Regulations as set forth below.

By Order of the Commission.

KENNETH F. PLUMB,
Secretary.

PART 35—FILING OF RATE SCHEDULES

1. Section 35.19a, Title 18, Code of Federal Regulations is amended to read as follows:

§ 35.19a Refund requirements under suspension orders.

(a) *Refunds.* (1) Unless otherwise ordered by the Commission, the public utility whose proposed increased rates and charges were suspended shall refund at such time and in such manner as required by final order of the Commission the portion of any increased rates and charges found by the Commission in that suspension proceeding not to be justified, together with interest as required in subparagraph (2) of this paragraph.

(2) Interest shall be paid on all amounts to be refunded as follows:

(i) At a rate of seven percent per annum on all excessive rates and charges collected prior to October 10, 1974;

(ii) At a rate of nine percent per annum on all excessive rates and charges collected on and after October 10, 1974, and nine percent per annum for all interest accruing on and after October 10, 1974 on refundable amounts collected prior to October 10, 1974, from the date of payment until refunded, except as provided in (iii) and (iv) below;

(iii) With respect to all refundable amounts held on or after (*the first day of the first calendar quarter after the date of issuance of a final order*), the amount of interest to be paid on such refunds for each calendar quarter shall be the adjusted average prime rate charged by commercial banks on short-term business loans, as calculated and announced by the Commission not later than the last day of the preceding quarter. The adjusted average prime rate is considered to be the average prime rate for the most recent three full months reported in the *Federal Reserve Bulletin*, rounded upward or downward, as appropriate, to the nearest half of a percentage point; and

(iv) With respect to all refundable amounts held on or after the (*first day of the first month beginning after the date of issuance of a final order*), the amount of interest required to be paid on such refunds shall be compounded monthly.

(3) Any public utility required to make refunds pursuant to this section shall bear all costs of such refunding.

(b) *Reports.* Any public utility whose proposed increased rates or charges were suspended and have gone into effect pending final order of the Commission pursuant to section 205(e) of the Federal Power Act shall:

(1) Keep accurate accounts in detail of all amounts received under the increased rates or charges which become effective after the suspension period, for each billing period, specifying by whom and in whose behalf such amounts were paid;

(2) Submit annually on or before March 31 of each year to the Commission, in writing (original and one copy) and under oath the following information concerning each billing period for each purchaser for the previous calendar year:

(i) The monthly billing determinants of electricity sold and delivered to each purchaser under the suspended agreements or tariffs;

(ii) The revenues which would result from such sales if they were computed under the rates in effect immediately prior to the date the proposed increased rates or charges become effective;

(iii) The revenues resulting from such sales as computed under the proposed increased rates or charges that became effective after the suspension period; and

(iv) The difference between those revenues computed in subparagraphs (ii) and (iii) of this paragraph.

(3) The Director of the Office of Electric Power Regulation may require reports on a more frequent basis in individual cases when it is deemed appropriate and necessary to do so.

PART 154—RATE SCHEDULES AND TARIFFS

2. Section 154.67, Title 18, Code of Federal Regulations is amended to read as follows:

§ 154.67 Suspended changes in rate schedules; motions to make effective at end of period of suspension; procedure.

(a) *Effect of suspended changes in rate schedules.* If a rate suspension proceeding initiated under section 4(e) of the Natural Gas Act has not been concluded and an order issued by the Commission at the expiration of the suspension period, unless otherwise ordered by the Commission, the proposed change of rate, charge, classification, or service shall go into effect

upon motion of the pipeline company proposing the change so long as the pipeline company complies with all requirements of this section. The proposed rate, charge, classification, or service shall become effective as of the date of receipt of such motion by the Commission or the expiration of the suspension period, whichever is later.

(1) Concurrently with the motion to make the suspended rate effective, the company shall file an undertaking, described in subparagraph (2) below, to comply with provisions of paragraphs (b) and (c) of this section. Three copies of the motion and undertaking shall be filed. Unless notified to the contrary by the Secretary of the Commission within 30 days from the date of filing, such motion and undertaking shall be deemed to be satisfactory and to have been accepted for filing.

(2) The pipeline company shall file with the Secretary an undertaking to comply with the terms of this section. Such undertaking shall be signed by a responsible officer of the company, evidenced by proper authority from the Board of Directors, and accompanied by a certificate showing service of copies thereof upon the purchasers under the rate schedules to be made effective by the motion of the company, and shall conform to the model undertaking below:

AGREEMENT AND UNDERTAKING OF [COMPANY] TO COMPLY WITH THE TERMS AND CONDITIONS OF SECTION 154.67 OF THE COMMISSION'S RULES AND REGULATIONS UNDER THE NATURAL GAS ACT IN RESPECT TO [COMPANY'S] MOTION TO HAVE ITS PROPOSED TARIFF SHEETS IN DOCKET NO. RP—— PLACED INTO EFFECT

In conformity with the requirements of § 154.67 of the Commission's rules and regulations under the Natural Gas Act [Company] hereby agrees and undertakes to comply with the terms and conditions of said section of the Commission's rules and regulations and has caused this agreement and undertaking to be executed and sealed in its name by its officers thereupon duly authorized in accordance with the terms of the resolution of its Board of Directors a certified copy of which is appended hereto this —— day of ————, 19——.

By:————————
[Company]
Attest:————————.

(b) *Reports.* Any pipeline company whose proposed increased rates or charges were suspended and have gone into effect pending final order of the Commission pursuant to section 4(e) of the Natural Gas Act shall:

(1) Keep accurate accounts in detail of all amounts received by reason of the increased rates or charges made effective as provided in this order, for each billing period.

(2) Submit annually on or before March 31 of each year to the Commission, in writing and under oath, an original and one copy of the following information for each billing period, for each customer for the previous calendar year:

(i) The monthly billing determinants of natural gas sold and transported to each purchaser under the suspended agreements or tariff;

(ii) The revenues which would result from such sales if they were computed under the rates in effect immediately prior to the date the proposed change become effective;

(iii) The revenues resulting from such sales as computed under the proposed increased rates or charges that become effective after the suspension period; and

(iv) The difference between the revenues computed in subparagraphs (ii) and (iii) of this paragraph.

(3) The Director of the Office of Pipeline and Producer Regulation may require reports on a more frequent basis in individual cases when it is deemed appropriate and necessary to do so.

(c) *Refunds.* (1) Any pipeline company that collects charges pursuant to this section shall refund at such time and in such manner as may be required by final order of the Commission, the portion of any increased rates and charges found by the Commission in that proceeding not to be justified, together with interest as required in subparagraph (2) of this paragraph.

(2) Interest shall be paid on all amounts to be refunded as follows:

(i) At a rate of seven percent per annum on all excessive rates and charges collected prior to October 10, 1974;

(ii) At a rate of nine percent per annum on all excessive rates and charges collected on and after October 10, 1974, and nine percent per annum for all interest accruing on and after

October 10, 1974 on refundable amounts collected prior to October 10, 1974, from the date of payment until refunded, except as provided in (iii) and (iv) below;

(iii) With respect to all refundable amounts held on or after (*the first day of the first calendar quarter after the date of issuance of a final order*), the amount of interest required to be paid on such refunds for each calendar quarter shall be the adjusted average prime rate charged by commercial banks on short-term business loans, as calculated and announced by the Commission not later than the last day of the preceeding quarter. The adjusted average prime rate is considered to be the average prime rate for the most recent three full months reported in the *Federal Reserve Bulletin*, rounded upward or downward, as appropriate, to the nearest half of a percentage point; and

(iv) With respect to all refundable amounts held on or after the (*first day of the first month beginning after the date of issuance of a final order*), the amount of interest required to be paid on such refunds shall be compounded monthly.

(3) Any pipeline company required to make refunds pursuant to this section shall bear all costs of such refunding.

(4) If the pipeline company, acting in conformity with the terms and conditions of the undertaking required by this section, makes the refunds as may be required by order of the Commission, the undertaking shall be discharged; otherwise, it shall remain in full force and effect.

3. Section 154.102, Title 18, Code of Federal Regulations is amended to read as follows:

§ 154.102 Suspended change in rate schedules; motion to make effective at end of period of suspension; procedure.

(a) *Effectiveness of suspended rate schedules.* If a rate suspension proceeding initiated under section 4(e) of the Natural Gas Act has not been concluded and an order issued by the Commission at the expiration of the suspension period, unless otherwise ordered by the Commission, the proposed change of rate, charge, classification, or service shall go into effect as the legally effective rate upon motion of the independent producer proposing the change so long as the independent producer complies with all requirements of this section. The Secretary, upon receipt of such a motion, shall, if the motion is legally adequate for the purpose, notify the movant that the proposed change shall be effective as provided in this section. The Secretary shall refer to the Commission any motion requesting that a change in rate, charge, classification, or service be made effective, if in his judgment the motion should receive the specific attention of the Commission.

(1) Three copies of the motion and any accompanying papers shall be filed with the Commission.

(2) The proposed rate, charge, classification, or service shall become effective as of the date of receipt of such motion by the Commission or the expiration of the suspension period, whichever is later.

(b) *Undertaking to comply.*

(1) There shall be filed by the independent producer a surety bond, or other undertaking, to be approved by the Secretary to comply with the provisions of paragraphs (c) and (d) of this section. The bond or undertaking may be filed concurrently with the motion to make the increased rates effective. If with his motion the producer has not filed a satisfactory bond or undertaking such bond or undertaking must be filed within 30 days after the issuance of the Secretary's notice provided for in paragraph (a) of this section. Unless notified to the contrary by the Secretary of the Commission within 30 days from the date of filing, such bond or undertaking shall be deemed to be satisfactory and to have been accepted for filing.

(2) In compliance with subparagraph (1) of this paragraph, an independent producer may file a general undertaking affording blanket refund coverage of any present and future rate increases suspended under section 4(e) of the Natural Gas Act and collected subject to refund thereunder. Upon acceptance of such general undertaking, the producer need not file further refund assurance when filing a motion to make increased rates effective

unless specifically required to do so by order of the Commission.

(c) *Record keeping.* During the time an increased rate is effective pursuant to the provisions of this section, the independent producer shall:

(1) Keep accurate accounts in detail of all amounts received by reason of the increased rates or charges for each billing period;

(2) Record for each purchaser:

(i) The monthly billing determinants of natural gas sales to each purchaser;

(ii) The revenues resulting from such sales as computed under the rates in effect immediately prior to the date the proposed change because effective;

(iii) The revenues resulting from such sales as computed under the proposed change that became effective after the suspension period; and

(iv) The difference between the revenues computed under subparagraphs (ii) and (iii) of this paragraph.

(d) *Refunds.* (1) Any independent producer that collects charges pursuant to this section shall refund at such times, in such amounts to the persons entitled thereto and in such manner as may be required by final order of the Commission, the portion of any increase rate found by the Commission in that proceeding not justified, together with interest thereon as required in subparagraph (2) of this paragraph.

(2) Interest shall be paid on all amounts to be refunded as follows:

(i) At a rate of seven percent annum on all excessive rates and charges collected prior to October 10, 1974;

(ii) At a rate of nine percent per annum on all excessive rates and charges collected on and after October 10, 1974, and nine percent per annum for all interest accruing on and after October 10, 1974, from the date of payment to the producer until refunded, except as provided in (iii) and (iv) below;

(iii) With respect to all refundable amounts held on or after (*the first day of the first calendar quarter after the date of issuance of a final order*), the amount of interest required to be paid on such refunds for each calendar quarter shall be the adjusted average prime rate charged by commercial banks on short-term business loans, as calculated and announced by the Commission not later than the last day of the preceeding quarter. The adjusted average prime rate is considered to be the average prime rate for the most recent three full months reported in the *Federal Reserve Bulletin*, rounded upward or downward, as appropriate, to the nearest half of a percentage point;

(iv) With respect to all refundable amounts held on or after (*the first day of the first month beginning after the date of issuance of a final order*), the amount of interest required to be paid on such refunds shall be compounded monthly; and

(v) With respect to all refundable amounts no interest is required to be paid on any portion of a refund which represents payments of royalties or taxes to Federal or State governmental authorities, except to the extent that such authorities pay interest to the producer when refunding overpayments of royalties or taxes.

(3) Any independent producer that is required to refund amounts collected pursuant to this section shall bear all costs of any such refunding;

(4) If the producer, acting in conformity with the terms and conditions of the bond or undertaking, makes the refunds as may be required by order of the Commission, the bond or undertaking shall be discharged; otherwise it shall remain in full force and effect.

4. Section 154.38, Title 18, Code of Federal Regulations is amended in subparagraph (d)(4)(iv)(c), by revising the first three sentences to read as follows:

§ 154.38 Composition of rate schedule.

* * * * * * *

(d) *Statement of rate.* * * *

(4) * * *

(iv) * * *

(c) Carrying charges shall be computed based on the ending balances in Account 191. The rate for computation of carrying charges shall be the current rate of interest on pipeline refunds established by the Commission. * * *

PART 273—COLLECTION AUTHORITIES; REFUNDS

5. Section 273.302(e)(1), Title 18, Code of Federal Regulations is amended to read as follows:

§ 273.302 Refunds of interim collections.

* * * * *

(e) * * *

(1) Within 45 days after a determination that a first sale is not eligible for the price collected under this part becomes final, the seller shall refund to the purchaser by cash or check the refund amount computed under paragraph (g), together with interest at a rate computed in accordance with the provisions set forth in § 154.102(d), on the excess charges that have been collected from the date of payment until the date of refund.

6. Title 49, Code of Federal Regulations, is amended by adding a new Chapter XV to read as follows:

CHAPTER XV—FEDERAL ENERGY REGULATORY COMMISSION

PART 1605—REFUND REQUIREMENTS FOR OIL PIPELINES

§ 1605.95 Suspended rate schedules; procedure; refund requirements, administered by the Federal Energy Regulatory Commission.

(a) *Effectiveness of suspended rate schedules.* If a rate suspension proceeding initiated under section 15(7) of the Interstate Commerce Act has not been concluded and an order issued by the Federal Energy Regulatory Commission at the expiration of the suspension period, unless otherwise ordered by the Federal Energy Regulatory Commission, the proposed rate, charge, classification, or service shall go into effect so long as the pipeline company complies with all requirements of this section.

(b) *Undertaking to comply.*

(1) The pipeline company shall file an undertaking, described in subparagraph (2) below, to comply with provisions of paragraphs (c) and (d) of this section. Three copies of the undertaking shall be filed. Unless notified to the contrary by the Secretary of the Federal Energy Regulatory Commission within 30 days from the date of filing, such undertaking shall be deemed to be satisfactory and to have been accepted for filing.

(2) The pipeline company shall file with the Secretary an undertaking to comply with the terms of this section. Such undertaking shall be signed by a responsible officer of the company, evidenced by proper authority from the Board of Directors, and accompanied by a certificate showing service of copies thereof upon the purchasers under the rate schedules to be made effective by the company, and shall conform to the model undertaking below:

AGREEMENT AND UNDERTAKING OF [COMPANY] TO COMPLY WITH THE TERMS AND CONDITIONS OF 49 CFR § 1605.95 THE FEDERAL ENERGY REGULATORY COMMISSION'S RULES AND REGULATIONS UNDER THE INTERSTATE COMMERCE ACT

In conformity with the requirements of 49 CFR § 1605.95 of the Federal Energy Regulatory Commission's rules and regulations under the Interstate Commerce Act [Company] hereby agrees and undertakes to comply with the terms and conditions of said section of the Federal Energy Regulatory Commission's rules and regulations and has caused this agreement and undertaking to be executed and sealed in its name by its officers thereupon duly authorized in accordance with the terms of the resolution of its Board of Directors a certified copy of which is appended hereto this —— day ————, 19——.

By:————————
[Company]

Attest:————————.

(c) *Recordkeeping.* Any pipeline company whose proposed rates or charges were suspended and have gone into effect pending final order of the Federal Energy Regulatory Commission pursuant to section 15(7) of the Interstate Commerce Act shall:

(1) Keep accurate accounts in detail of all amounts received by reason of the rates or charges made effective as provided in this order, for each billing period including the following information for each billing period, for each customer:

(i) The monthly billing determinants of petroleum or petroleum by-products sold and transported to each purchaser under the suspended agreements or tariff;

(ii) The revenues which would result from such sales if the were computed under the rates in effect immediately

prior to the date the proposed change became effective, if applicable;

(iii) The revenues resulting from such sales as computed under the proposed increased rates or charges that became effective after the suspension period; and

(iv) The difference between the revenues computed in subparagraphs (ii) and (iii) of this paragraph, if applicable.

(d) *Refunds.* (1) Any pipeline company that collects charges pursuant to this section shall refund at such time and in such manner as may be required by final order of the Federal Energy Regulatory Commission, the portion of any rates and charges found by the Federal Energy Regulatory Commission in that proceeding not to be justified, together with interest as required in subparagraph (2) of this paragraph.

(2) Interest shall be paid on all amounts to be refunded as follows:

(i) With respect to all refundable amounts held on or after (*the first day of the first calendar quarter after the date of issuance of a final order*), the amount of interest required to be paid on such refunds for each calendar quarter shall be the average prime rate charged by commercial banks on short-term business loans, as calculated and announced by the Federal Energy Regulatory Commission not later than the last day of the preceding quarter. The average prime rate is considered to be the average for the most recent three full months reported in the *Federal Reserve Bulletin*, rounded upward or downward, as appropriate, to the nearest half of a percentage point; and

(ii) With respect to all refundable amounts held on or after (*the first day of the first month beginning after the date of issuance of a final order*), the amount of interest required to be paid on such refunds shall be compounded monthly.

(3) Any pipeline company required to make refunds pursuant to this section shall bear all costs of such refunding.

(4) If the pipeline company, acting in conformity with the terms and conditions of the undertaking required by this section, makes the refunds as may be required by order of the Federal Energy Regulatory Commission, the underaking shall be discharged; otherwise, it shall remain in full force and effect.

APPENDIX A—COMMENTORS AND PETITIONERS, DOCKET NO. RM77-22

Mobil Oil Corporation
New England Power Company
Michigan-Wisconsin Pipe Line Company
Southland Royalty Company
Amoco Production Company
Colorado Interstate Gas Company
Nortwest Pipeline Corporation
Northern Illinois Gas Company
Interstate Natural Gas Association of America
Southern Natural Gas Company
Sienna Pacific Power Company
Gulf Oil Corporation
Duke Power Company
Algonquin Gas Transmission Company
Bay State Gas Company, *et al.*
Pacific Gas and Electric Company
Pacific Gas Transmission Company
Gulf Power Company
United Gas Pipe Line Company
Texaco, Inc.
Exxon Corporation
Consumers Power Company
Consolidated Edison Company of New York, Inc.
Municipal Customer Groups
American Public Gas Association
Dayton Power and Light Company
Public Wholesale Customers
American Public Power Association
Southern California Edison Company
Kentucky-West Virginia Gas Company
Connecticut Light and Power Company
Holyoke Power and Electric Company
Holyoke Water Power Company
Western Massachusetts Electric Company
Placid Oil Company
Columbus and Southern Ohio Electric Company
Tennessee Gas Pipeline Company, A Division of Tenneco, Inc.
Illinois Power Company
Publicly Owned Systems
Northern Natural Gas Company
Dr. Marion H. Kahn
Northern Minnesota Municipal Electric Association
Atlantic Richfield Company
Public Service Company of Colorado
Arizona Public Service Company, *et al.*
Union Oil Company of California
Kent-McGee Corporation
Phillips Petroleum Company
Ensearch Exploration Company
Tenneco Oil Company
Sun Oil Company (Delaware)
Indiana Statewide Rural Electric Cooperative, Inc.
Continental Oil Company

APPENDIX B—INDIANA MUNCIPAL ELECTRIC ASSOCIATION

Cities and Towns of:

Advance
Bainbridge
Bargersville
Centerville
Coatesville
Covington
Darlington
Dublin
Dunreith
Edinburg
Flora
Greendale
Greenfield
Hagerstown
Jamestown
Knightstown
Ladoga
Lawrenceburg
Lebanon
Lewisville
Linton
Middletown
Montezuma
Paoli
Pendleton
Pittsboro
Rising Sun
Rockville
Scottsburg
South Whitley
Spiceland
Straughn
Thorntown
Tipton
Veedersburg
Waynetown
Williamsport

Crawfordsville Electric Light and Power of the City of Crawfordsville

¶ 32,013 Rules Relating to Investigations

44 F. R. 21586 (April 10, 1979).

[18 CFR Parts 1a, 1b]

Rules Relating to Investigations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission is proposing revised regulations relating to investigations as a result of comments on its interim regulations which have been in effect since June 14, 1978 (43 FR 27174, June 23, 1978). The interim regulations have been adopted to state clearly the Commission's policy and procedures for investigations conducted under the statutes it administers. The revisions are proposed based on the comments received and experiences of the Commission under the interim regulations and also because of new powers granted the Commission under the Natural Gas Policy Act of 1978, the Public Utility Regulatory Policies Act and the Outer Continental Shelf Act Amendments of 1978.

DATE: Comment due date: April 25, 1979.

ADDRESSES: All filings should reference Docket No. RM78–15 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Charles J. Freidman, Office of Enforcement, Federal Energy Regulatory Commission, Room 3106, 941 North Capitol Street, NE., Washington, D.C. 20426, (202) 275–0303.

SUPPLEMENTARY INFORMATION:

A. Background

On June 14, 1978, the Commission issued Order No. 8, effective immediately, establishing a new Part 1b to its rules of practice and procedure entitled Rules Relating to Investigations. 43 FR 27174 (June 23, 1978) The Commission adopted these new regulations "to state clearly the Commission's policy and procedures for investigations conducted under the statutes it administers." It made these regulations effective immediately. In addition, the Commission afforded interested parties an opportunity to submit comments, suggestions or revisions with respect to these regulations. The Commission received comments from sixteen corporations and organizations.

Based upon a review of these comments and upon experience, the Commission proposes to amend the existing regulations concerning Commission investigations, especially in light of the new powers recently granted the Commission under the Natural Gas Policy Act of 1978, the Public Utility Regulatory Policies Act and the Outer Continental Sheif Lands Act Amendments of 1978. Thus, the Notice of Proposed Rulemaking would establish a new Part 1a, setting forth the Commission's Rules Relating to Investigations (hereinafter referred to as the "Rules"). In general, this proposal would reorganize the provisions contained in Part 1b, delete certain of the provisions and add new provisions to correct misapprehensions made manifest by certain of the comments received in response to Order No. 8 and to explain more fully and clearly the procedures to be followed in certain Commission investigations.

B. Summary of the Proposed Regulations

The Commission proposes to establish a new Part 1a of Title 18, Code of Federal Regulations, consisting of procedures to implement the Commission's investigative responsibilities under the statues administered by the Commission. This proposal applies to all investigations conducted by the Commission, the Commission's Office of Enforcement, and any other designated officers of the

Commission. Section 1a.1 describes the scope and applicability of the Rules and the authority to conduct investigations. Sections 1a.2 through 1a.4 relate to requests for Commission investigations and describe the nature and conduct of preliminary investigations and formal investigations. Sections 1a.5 through 1a.9 relate to the issuance and service of and response to subpoenas, the applicability of certain of the Commission's information-gathering powers during investigations, sanctions for non-compliance with the Commission's compulsory process, the preparation and use of transcripts generated during Commission investigations, and the rights of witnesses and other persons during Commission investigations. Section 1a.10 controls appearance and practice before the Commission during investigations while § 1a.11 describes certain criminal penalties pertinent to investigations. Section 1a.12 describes the final stages of investigations, § 1a.13 provides for the non-public conduct of preliminary and formal investigations under Part 1a, and § 1a.14 describes requests for confidential treatment.

1. Scope and Commencement of Commission Investigations

Section 1a.1, which sets forth the general scope and applicability of the rules, represents a consolidation of §§ 1b.2 and 1b.3. This section makes clear that the Rules apply to investigations conducted by the Commission or its staff pursuant to section 307 of the Federal Power Act (16 U.S.C. 825f), as amended, section 14 of the Natural Gas Act (15 U.S.C. 717m), section 12 of the Interstate Commerce Act (49 U.S.C. 12), sections 501(a) and 508 of the Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, or any other statute administered by the Commission. Section 1a.2, which sets forth the procedures regarding requests for investigations, replaces section 1b.8.

Several of the comments have suggested that Part 1b grants too much discretion to the Commission and its staff regarding the conduct of non-public investigations and fail to provide adequate procedural due process to persons being investigated by the Commission.

In many respects, the various objections to the investigatory rules exhibit a misconception of the role played by investigations within the regulatory context. It has long been settled that an administrative agency's "investigative function * * * is essentially the same as the grand jury's * * *" As the Supreme Court has said with reference to the investigatory power of the Federal Trade Commission:

> It has the power of inquisition, if one chooses to call it that, which is not derived from the judicial function. It is more analogous to the Grand Jury, which does not depend on a case or controversy for power to get evidence but can investigate merely on suspicion that the law is being violated, or even just because it wants assurance that it is not. When investigative and accusatory duties are delegated by statute to an administrative body, it too may take steps to inform itself as to whether there is probable violation of the law. *United States* v. *Morton Salt Co.*, 338 U.S. 632, 642–3 (1950).

It is also well settled that a non-adjudicative, fact-finding investigation should not be governed by the same procedural due process standards as would apply to an adjudicative proceeding. The need to confer upon a person being investigated the full panoply of procedural due process rights is obviated when, as the Supreme Court observed in its discussion of the investigatory functions performed by the Civil Rights Commission and the Federal Trade Commission, "* * * any person investigated * * * will be accorded all the traditional judicial safeguards at a *subsequent adjudicative proceeding, * * * should some type of adjudicative proceeding subsequently be instituted.*" *Hannah* v. *Larche*, 363 U.S. 420, 446 (1960) (emphasis added).

A number of Commission enforcement actions will be preceded by Commission investigations, which will differ significantly in structure and purpose from the adversary proceedings which may follow. The purpose of a

Commission investigation is to determine whether any persons or entities have violated laws, regulations, or orders administered or issued by the Commission, and, if so, what formal enforcement action should be taken. Although civil remedies, criminal penalties, and administrative sanctions can be imposed in Commission enforcement cases, a Commission investigation is a "non-adversary" inquiry or interrogation conducted to develop facts to enable the Commission to determine whether grounds exist for the institution of formal adversary proceedings. Thus, given the protections afforded in subsequent adversary proceedings, there is no need to transform investigations into adjudicative proceedings, which would "sterilize * * * investigations by burdening them with trial-like procedures." *Hannah* v. *Larche, supra,* 363 U.S. at 448.

2. Preliminary and Formal Investigations

Sections 1a.3 and 1a.4 describe the nature and conduct of preliminary investigations and of formal investigations. The proposed revision is intended to emphasize that the Commission's Office of Enforcement is principally responsible for the conduct of preliminary and formal investigations under this Part and to clarify the distinctions between (1) preliminary investigations, during which no compulsory process is issued, no testimony is compelled, and no oaths are administered, and (2) formal investigations, during which such events do take place pursuant to a Commission order of investigation.

Section 1a.3 represents a revision and consolidation of portions of §§ 1b.1, 1b.6, 1b.7, 1b.9 and 1b.11. Similarly, § 1a.4 represents a revision of portions of §§ 1b.1, 1b.5, 1b.7, 1b.9, 1b.10, 1b.11, and 1b.13.

a. *The preliminary investigation.* As provided in § 1a.3, the objective of the preliminary investigation is to gather facts and determine whether there is a likelihood that a violation has occurred, is occurring, or is about to occur. Since it is an informal procedure and the Commission's subpoena power is not invoked, the Commission, the Commission's Office of Enforcement or other staff members designated by the Commission request the voluntary cooperation of persons from whom relevant information may be obtained. Individuals may be requested to speak informally with staff members, statements may be taken, and documents requested. Evidentiary material compiled by the staff in the preliminary investigation remains non-public unless the Commission orders that it be made public. Section 1a.3 makes clear that no person may intervene in any preliminary investigation.

Various comments to Order No. 8 questioned the broad scope of Commission investigations and specifically of preliminary investigations. The Commission frequently receives information which suggests or alleges that applicable laws, regulations, or orders have been or are about to be violated. Such information may be received from state and federal authorities. It may be contained in periodic reports, newspaper articles, advertisements or other periodicals. Information may also come from an investigation into a related matter. The filing of a written statement is not a requirement, and a preliminary investigation may be pursued without it. It should also be emphasized that the Commission may conduct a threshold investigation to determine whether the questioned activities or facts come within the jurisdiction of the Commission.

The Commission is charged with enforcing certain laws and regulations and therefore may take some action when there is an indication of a prohibited activity. On the other hand, because the Commission has limited resources, every lead, even when amplified by the information obtained in a preliminary investigation, cannot or need not be followed up with a full scale formal investigation. The Commission

has a number of alternatives after completing a preliminary investigation, including, but not limited to, the following: (1) A formal investigation, (2) a referral to state or local authorities, (3) an informal disposition of the matter by obtaining voluntary compliance, or (4) a further investigation and report to the Commission by independent accountants, legal counsel and boards of directors. Of course, a preliminary investigation may also lead to a determination that no further action is necessary.

b. *The formal investigation.* As proposed, the rules would be amended to describe more fully (1) the initiation of formal investigations, (2) the Commission's order of investigation, (3) the oath administered to witnesses, (4) participation in formal investigations, (5) the non-public nature of most formal investigations, and (6) procedures relating to public formal investigations.

If, after a preliminary investigation, it appears to the staff that there is a likelihood of a violation or that subpoena power is needed to ascertain more facts, § 1a.4 provides for the conduct of formal investigations by the Commission, either by the Commission itself or by one or more members of the Commission or its staff designated by the Commission to conduct a formal investigation. Section 1a.4 specifically provides for the staff to seek authorization from the Commission to institute a formal investigation and utilize subpoena power. If the Commission concurs with the staff recommendation, a formal order of investigation is issued which, among other things: (1) Delineates the scope of the investigation, including the statutes, rules and regulations which may have been violated and the possible violative activities that the staff is authorized to investigate, (2) names of subjects of the investigation, and (3) designates the members of the Commission or its staff authorized by the Commission to issue subpoenas and interrogatories and to question persons under oath. Any person named in the formal order as well as persons who are not named in such formal order may be subpoenaed to testify or to produce their own records as long as such testimony or records are relevant to the investigation. Finally, § 1a.4 makes it clear that no person may intervene in any formal investigation.

In response to various comments, the Commission proposes to replace former § 1b.16(d) of Order No. 8 with § 1a.4(f) of the rules. This revised section provides that the Commission may order a formal investigation to be conducted in public. Although the rules provide that the Commission shall issue notice of the institution of such public formal investigation and, where appropriate, of the time and place of the taking of testimony of witnesses during such investigation, § 1a.4(c) further provides the Commission with flexibility to adopt special or additional procedures in connection with such public formal investigation.

Some of the comments to Order No. 8 suggested that the Commission adopt the practice of notifying a person who is the subject of an investigation and against whom no further action is contemplated that the staff has concluded its investigation of the matters referred to in the formal order of investigation and determined that it will not recommend the commencement of an enforcement action against such person. Although this suggestion may be superficially appealing, the Commission does not believe that it should adopt a rule or procedure under which the Commission in each instance will inform parties when its investigation has been concluded. We take this position because it is often difficult to determine whether an investigation has been concluded or merely suspended and because an investigation believed to have been concluded may be reactivated as a result of unforeseen developments. Under such circumstances, advice that an investigation has been concluded could be misleading. Thus, the proposed changes contain no formal requirements that the Commission notify every

subject of a non-public formal investigation that it has been terminated.

The Commission has provided, however, pursuant to § 1a.4(f), that the staff may in cases where such action appears appropriate advise persons under inquiry in a public formal investigation that the Commission has terminated such investigation and that the staff will not at that time recommend the commencement of an enforcement proceeding against a particular person or entity. The Commission would make clear, however, that such advice, if given, must in no way be construed as indicating that such person has been exonerated or that no action may ultimately result from the staff's investigation of the particular matter. The Commission further stresses that if persons under inquiry are advised of the termination of a public formal investigation, they should be aware that the attempted use of such communications as a purported defense in any civil or criminal action that might subsequently be brought against that party would be inappropriate and improper.

c. *Issuance and service of subpoenas, response to subpoenas, and witness fees in formal investigations.* Section 1a.5 sets forth the procedure for issuing subpoenas, the service of subpoenas, the payment of witness fees and the manner of response to subpoenas. The proposal makes clear that a party subpoenaed during an investigation may assert constitutional and federal common law privileges. Thus, for example, the Fifth Amendment privilege against compulsory self-incrimination may be asserted. The witness cannot, however, merely refuse to appear; he or she must appear on the return date and assert a privilege. As in any other judicial or administrative forum, the subpoena requires a personal appearance and cannot be satisfied by appearance of counsel.

In response to various comments to Order No. 8, the Commission proposes to issue Rules relating to subpoenas (1) to provide that a subpoena may only be served upon a person's attorney when such attorney represents such person in the particular pending investigation, (2) to provide for the payment of witness fees and mileage expenses, and (3) to clarify the procedures to be followed if any subpoenaed documents are withheld for any reason, including a claim of privilege.

d. *Exercise of other information-gathering powers during investigations.* Section 1a.6 describes the Commission's authority under section 10(a) of the Natural Gas Act, U.S.C. 717i(a), section 304(a) of the Federal Power Act, 16 U.S.C. 825c(a), and section 20(1) of the Interstate Commerce Act, 49 U.S.C., 101(l), to require by order special reports, to prescribe the manner and form in which such reports shall be made, and to require from jurisdictional companies specific answers to all questions upon which the Commission may need information. Pursuant to § 1a.6. any officer authorized by the Commission to conduct a formal investigation may, by letter or other written mechanism, require natural-gas companies, hydroelectric licensees, oil pipeline companies and public utilities to answer under oath specific questions promulgated by such officer in a special report to be filed with the Commission. Such reports shall be made under oath, unless the Commission otherwise specifies.

Pursuant to section 508(b) of the Natural Gas Policy Act of 1978, the Commission is also empowered, among other things, to require by general or special order any person who is engaged in the production, processing, refining, transportation by pipeline, sale, or distribution (at other than the retail level) of energy recourses to submit answers in writing to interrogatories and to request for reports or for other information within a reasonable time period and under oath or otherwise. Section 508(b) also gives the Commission authority to conduct physical inspections at energy facilities and business premises, to inventory and sample any stock of energy resource therein, and to examine and copy any books, records, papers or other

documents relating to any such energy information and to question persons as the Commission or its designated officers may deem necessary, whether under oath or otherwise. Section 1a.6 (c) and (d) would allow the Commission or any of its designated officers during formal investigations to obtain information through physical inspections of energy facilities and business premises and through other requests.

e. *Sanctions for non-compliance with compulsory process and orders in formal investigations.* Section 1a.7 clarifies that the Commission may seek the aid of the appropriate United States District Court or of the Attorney General in order to obtain compliance with the Commission's compulsory process or orders issued during formal investigations. Section 1a.7 would replace § 1b.15 of Order No. 8.

f. *Transcripts.* Section 1a.8, which would replace section 1b.12, guarantees that any person who has provided a statement or testimony in an investigation under this Part shall be entitled to procure a copy of the official transcript of such statement or testimony, except that in certain limited circumstances, such person may be limited to an inspection of such transcript. This provision is wholly consonant with the Administrative Procedure Act, which provides that "in a non-public investigatory proceeding the witness may for good cause be limited to inspection of the official transcript of his testimony." 5 U.S.C. § 555(c).

Several of the comments to Order No. 8 recommended that the Commission provide witnesses with an absolute right to obtain a copy of their transcripts and to provide their own reporters in Commission investigations. The Commission believes, however, that it may be necessary in certain circumstances to deny a witness a copy of the transcript of his or her statement or testimony. As one court has noted, "non-public investigatory proceedings * * * 'might be thwarted in certain cases * * * if witnesses were given a copy of their transcript, [since] suspected violators would be in a better position to tailor their own testimony to that of the previous testimony, and to threaten witnesses about to testify with economic or other reprisals.' " *LaMorte v. Mansfield,* 438 F.2d 448, 451 (2nd Cir. 1971) (citation omitted). The commission also prefers the procedure whereby the officer or officers conducting the investigation designates one reporter to take the verbatim transcript of this nonadversary proceeding. Regarding the comments to Order No. 8 seeking clarification as to when requests for transcripts properly may be made, such requests would be appropriate before, during or after the examination of any witness, in accordance with the provisions of § 1a.8.

3. Rights and Obligations of Witnesses and Other Persons During Preliminary and Formal Investigations

Section 1a.9(a), which includes matters covered by section 1b.16 of Order No 8, provides that a subpoenaed person has an absolute right to inspect the formal order of investigation, and the person will ordinarily be provided a copy of the formal order unless the disclosure is inconsistent with the privacy of the persons or entities under investigation or the unimpeded conduct of the investigation. The Commission would not adopt the suggestion that the formal order of investigation be automatically "served" on "parties" to the investigation as Commission investigations are not adversary proceedings.

Various comments have suggested that witnesses in preliminary investigations should also be afforded the right to counsel. The Commission agrees. Section 1a.9(b) would grant a witness the right to be accompanied, represented and advised by legal counsel, whether such witness' appearance is pursuant to subpoena or voluntary. Section 1a.9(b) would require no special qualifications, examinations, or admission procedures for practice before the Commission during Commission investigations. An attorney may practice before the Commission if

he or she is admitted to practice before the U.S. Supreme Court, the Highest court of any state or territory, or the courts of the District of Columbia. Section 1a.9(b) sets forth the permissible conduct of counsel at a witness' examination as (1) advising the witness during any examination, and (2) making summary notes during the examination solely for use of the witness and witness' counsel. Section 1a.9(b) would also permit the witness at the conclusion of an examination to make a statement on the record to clarify any previous answer or otherwise. Restricting the role of counsel in Commission investigations is intended to ensure that the officer in charge of the investigation will conduct the examination in an unimpeded manner and that the examination will flow freely without interruption and unwarranted objection.

Section 1a.9 also describes other rights of witnesses, including the right against self-incrimination, the right to submit statements and other information, as well as provisions relating to immunity and sequestration. Although many of the comments received by the Commission to Order No. 8 recommend elimination of the latter provision, § 1a.9(e), which provides that witnesses may be sequestered and prohibited from being present during the examination of other witnesses, is necessary to protect the integrity of the investigative fact-finding process since "witnesses may, and often do, shape their testimony to match that given by other witnesses within their hearing. To prevent such matching of testimony is the prime purpose of putting witnesses under the [sequestration] rule." *Charles* v. *United States*, 215 F.2d 825, 827 (9th Cir. 1954).

Finally, § 1a.9(d) provides persons involved in a Commission investigation with the right to submit any documents, statements of fact, memoranda of law, or other information setting forth his or her interest and position regarding the subject matter of the investigation.

4. Appearance and Practice Before the Commission During Investigations

The parameters of appearances and practice before the Commission during investigations, which were formerly set forth in §§ 1b.16 and 1b.17 of Order 8, would be in § 1a.10, including procedures to be followed in situations of multiple representation by counsel. Although various comments to Order No. 8 recommended that the Commission delete the rule permitting the suspension or disbarment of an attorney from practice before the Commission, the Commission believes strongly that the integrity of the regulatory process is best maintained and preserved by continuing to ensure that all persons appearing or practicing before the Commission during investigations possess the requisite qualification to represent others and do not engage in unethical or improper professional conduct.

Many comments to Order No. 8 also opposed the concept embodied in § 1a.10, whereby an attorney may be prohibited from being present during the testimony of any other witness when such presence will obstruct or impede an investigation. This regulation, like § 1a.9(e), is designed to prevent the "matching of testimony" by witnesses. It has been recognized that "the purpose of sequestration could be defeated by an attorney advising witnesses as to the testimony which has been given by others." *Securities and Exchange Commission* v. *Higashi*, 359 F.2d 550, 552 (9th Cir. 1966). It should be emphasized that this power is intended to be exercised sparingly, and only in those instances where such multiple representation obstructs or may tend to obstruct the investigation.

Several comments to Order No. 8 questioned the relationship between the investigatory regulations and the Commission's regulation concerning *ex parte* communications, i.e. § 1.4(d). In revising § 1b.17 to make clear that only the provisions of § 1.4(b) apply to Commission investigations, the

Commission seeks to emphasize that the *ex parte* provisions do not apply to the conduct of Commission investigations, which are not "on-the-record proceedings" covered by § 1.4(d).

5. Final Stages of Investigations

In response to various comments, the Commission would expand Part 1b to include procedures and policy concerning submissions, consent agreements, and the various enforcement alternatives available to the Commission where it appears, as a result of its fact-finding investigations, that there has been a violation of any act, rule, regulation or order. Section 1a.12 therefore represents a revision of § 1b.19.

a. *Notification prior to enforcement actions; submissions.* One criticism of Part 1b of the Commission's rules has been that the Commission does not afford persons under investigation an opportunity to present their positions to the Commission before proceedings are brought against them or the matter is referred criminally. We believe it would seriously undermine the Commission's enforcement efforts to require as a matter of right the pre-notification of all persons who may be named in a Commission action or who may be proceeded against civilly or criminally of the possibility that such action might occur and to afford an opportunity to be heard in each instance before the Commission. The only actions that the Commission can initiate are those which already include all the appropriate due process safeguards. Moreover, it is only after there has been notice and opportunity for hearing that administrative action can be taken against any party. Thus, to add an additional procedural layer, namely, a requirement for argument or hearing on the question of whether or not to institute a proceeding, would, in the Commission's view, unduly delay the disposition of matters and would seriously undermine the Commission's enforcement program. Moreover, affording this right to persons under investigation without affording the same right to other interested persons having adverse interests, such as consumers, is unsatisfactory and inequitable. There can be no fairer procedure than having charges aired in a duly constituted forum where all parties are afforded their full legal rights. Furthermore, such delays would provide additional time for persons to dispose of assets, change contractual relationships, and carry on improper activities. It would also provide persons an opportunity to evade service, destroy records, and compromise or intimidate government witnesses. Finally, it is impractical and premature to provide for argument to resolve issues before issues have been joined by the commencement of civil proceedings in federal district court or administrative proceedings before the Commission.

Although the subject of an investigation does not have an absolute right to present his, her, or its case to the Commission, § 1a.12(a) provides for the officer or officers conducting the investigation to transmit to the Commission a subject's written statement together with any recommendation of such officer or officers. The Commission would emphasize that while it permits persons involved in an investigation to present a statement to it setting forth their interest and position, the Commission will not delay taking action which it has cause to believe is required pending the receipt of such a submission and, accordingly, it will be necessary if the material is to be considered that it be timely submitted. In determining what course of action to pursue, persons may find it helpful to discuss the matter with the officer or officers conducting the investigation. Section 1a.12(a) provides that the officers designated by the Commission to conduct an investigation may in their discretion advise prospective defendants or respondents of the general nature of the Commission's investigation, including such indicated violations as may pertain to them, and the amount of time that may be available for preparing a submission. The Commission's staff should have

discretion in this regard to protect the public interest and to avoid possible activities which would obstruct or delay necessary enforcement action.

Where a disagreement exists between the Commission's staff and a prospective defendant or respondent as to factual matters, this can be resolved in an orderly manner through litigation. Moreover, the Commission will not adjudicate issues of fact before actions have been commenced and evidence has been placed in the record. In addition, where a proposed administrative proceeding is involved, the Commission wishes to avoid the possible danger of apparent prejudice involved in considering conflicting contentions, especially as to factual matters, before the commencement of appropriate hearings before the Commission. Consequently, submissions by prospective defendants or respondents will normally prove most useful in connection with policy, or on occasion, legal questions, together with considerations relevant to a particular defendant or respondent which might not otherwise be brought clearly to the Commission's attention. Section 1a.12(a) provides that submissions by interested persons should be forwarded to the members of the Commission or its staff conducting or authorized to conduct the investigation, and should be clearly referenced to the specific investigation to which they relate. In the event a recommendation for the commencement of an enforcement action regarding any particular person is sent to the Commission by the officers conducting the investigation, any submissions by such persons would be presented to the Commission without alteration or amendment together with the recommendation of the officers conducting the investigation.

b. *Enforcement alternatives and Commission considerations.* At the conclusion of a Commission investigation, a number of alternatives are open to the Commission. In some cases, no further action may be taken. The matter may be referred to state or local authorities. The Commission may bring an injunctive action in federal district court seeking injunctive relief, may institute administrative proceedings, or may make a referral to the Attorney General for criminal prosecution. The staff may, of course, conclude that violations have not occurred or are not about to occur. Moreover, even though the staff has reason to believe that violations have occurred, it may recommend no further action. In determining whether additional action is warranted in cases where a violation has occurred, the Commission would consider a number of factors. Because flexibility and responsiveness to changing conditions are needed, it is impossible to enumerate all factors considered by the Commission. However, at least the following may be considered: the character, nature and scope of the alleged violations; the need for immediate action; whether the alleged violations involve any new theory or interpretation of law and the suitability of the matter to serve as a vehicle for doing so; the availability of any suitable remedies; the number of consumers and amount of harm to such consumers; the probability of a successful conclusion of the action and the type of relief or sanctions which could be obtained; whether the subject has taken curative steps to insure future compliance; whether the subject has made restitution to injured persons; the practices of a subject and the importance of alerting the industry and the public to the fact that the Commission has taken action with respect to the practices; the age of the violation; the difficulty of fashioning a sanction appropriate to the violation involved; and, generally, the impact of the case on the Commission's compliance and enforcement programs.

At the stage where it authorizes enforcement actions, the Commission would not attempt to determine factual issues or adjudicate liability. Its function is merely to determine whether a sufficient basis has been shown for alleging a violation of law. Even if it appears that a violation has occurred, however, the Commission has the

discretion to determine whether or not a formal enforcement action should be commenced and the form the enforcement action should take.

c. *Settlement of investigative matters before the Commission.* Another alternative to formal action, whether civil injunctive action or administrative proceeding, is for prospective defendants or respondents to settle such proceedings as a result of negotiations. Section 1a.12(c) proposes the Commission's policy on consent agreements. This policy provides that the Commission will not permit a defendant or respondent to consent to a judgment or order that imposes a sanction while denying the allegations in the complaint for injunctive relief or order instituting administrative proceedings. The purpose of such a policy is to avoid creating or permitting to be created at the time a decree is being entered or a sanction imposed any impression that the conduct alleged did not, in fact, occur.

6. Non-public Nature of Commission Investigations

Various comments to Order No. 8 questioned the need for non-public investigations. The Commission believes that § 1a.13, which would revise § 1b.9 of Order No. 8, is sufficient to protect the rights and privacy of persons involved in investigations.

The Rules would give the Commission authority to conduct either public or non-public investigations. It is anticipated, however, that most of the Commission's investigations will be conducted in a non-public manner and that the Commission will generally not exercise its discretionary authority to publish the fact that it is conducting a particular non-public investigation or the results of such investigation. Ordinarily, if formal enforcement actions follow an investigation, the action will move to a public forum, i.e., civil injunctive action in a federal district court, administrative proceedings before a Commission Administrative Law Judge, or criminal prosecution by the Attorney General. Administrative proceedings generally are public, although the Commission may hold non-public meetings. However, the Commission may announce the existence of an investigation to assure consumers, the energy industry, and the public of its concern in a particular area. The Commission may also announce the existence of an investigation in circumstances where the facts underlying the Commission investigation are widely known to the public through previously public administrative hearings.[1]

There have been suggestions in the comments to Order No. 8 that the Commission's staff might breach the Commission's usual practice of maintaining the non-public nature of investigations. The Commission disagrees with such an analysis of its staff's behavior during investigations. The Commission recognizes that an investigation is not a matter to be taken lightly and that repercussions may occur from the mere fact of an investigation. Although such consequences can sometimes be serious and should be minimized as much as possible, they must not be permitted to deter the Commission in the discharge of its enforcement activities. The multiple steps involved in issuing an investigative order have thus been developed because of the potential impact of the commencement of a formal investigation. Thus, investigations will generally be conducted in a non-public manner to ensure that the mere initiation of investigations by the Commission will not be interpreted to mean that the Commission has concluded that a violation of law has occurred.

7. Requests for Confidential Treatment of Information

Regarding requests for confidential treatment of information furnished to

[1] For example, this has recently occurred in the matters of *Tenneco Inc., et al.* Docket No. IN78-1, and *Florida Gas Transmission Company*, Docket No. IN78-2.

the Commission during investigations and the adequacy of the procedures for handling requests for confidential treatment, the Commission believes that § 1a.14, which revises § 1b.20 of Order No. 8, would be adequate to cover Commission investigations at this time.

8. Providing Adequate Due Process Safeguards

Various comments have alleged that Order No. 8 "give[s] rise to an ominous potential for abuse" and provides for "the abolition of basic procedural due process." We believe that such fears are unfounded and therefore the Rules are completely consistent with the requirements of the Administrative Procedure Act and of procedural due process as applied to Commission investigations.

The Commission has always been careful to assure the utmost protection of the individuals' rights, taking into account both substantive and procedural due process standards. The rules as proposed reflect the Commission's traditional and strict adherence to all procedural due process requirements. In this regard, persons summoned to appear in an investigation, are, among other things, advised of their right to counsel and that they need not give any evidence that may be incriminating. Such warnings go beyond constitutional requirements, which only provide the opportunity to consult with counsel where the witness is "in custody." Indeed, the rights afforded under Commission practice go beyond those afforded by most other government agencies. For example, the Commission's Rules would provide the right to counsel in informal as well as formal investigations, although Section 555(b) of the Administrative Procedure Act only requires the right to counsel where a witness is compelled to appear in person before an administrative agency. Further, witnesses are afforded the absolute right to inspect a copy of their investigative transcripts. Prior to beginning his or her testimony, a witness is also afforded the opportunity to read the Commission's order of investigation which is issued before a formal investigation is undertaken. The order of investigation specifically provides the witness information concerning the scope and nature of the investigation which far exceeds constitutional requirements and the practices of most other government agencies. This is of substantial assistance to the witness and his or her counsel in enabling them to make informed decisions with respect to furnishing records and giving testimony. The practices in this area have been judicially upheld as meeting all required standards.[3] Moreover, the use of an official reporter to take verbatim transcripts assures that there can be an effective review of the exact questions asked, the answers given, and counsel's statements and objections.

It should further be noted that the Commission would be kept fully informed and direct authorization by the Commission is required at every major step of the investigatory process. The authority to institute administrative proceedings or bring civil injunctive actions or refer cases for criminal prosecution is exclusively the prerogative of the Commission. There has been no delegation of these powers and the Commission only acts after it has reviewed and considered comprehensive staff reports.

C. Written Comment Procedures

The Commission invites interested persons to submit written comments, with data, views and other information concerning all facets of this proposal. Interested persons may participate by submitting comments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before April 25, 1979. Each person submitting a comment should include his or her name and address, identify the

[3] *See Hannah* v. *Larche*, 363 U.S. 420 (1959) and *United States* v. *Dosek*, 405 F. 2d 405 (8th Cir. 1968).

notice (Docket No. RM78–15), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of a person to whom communications concerning the regulations may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

(Federal Power Act, as amended, 16 U.S.C. 792, *et seq.* Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*, Interstate Commerce Act, as amended, 49 U.S.C. 1, *et seq.*, Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1331, *et seq.*, Mineral Leasing Act of 1920, as amended, 30 U.S.C. 185, *et seq.*, Department of Energy Organization Act, Pub. L. No. 95–91, E.O. 12009, 423 FR 46267, Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, Public Utilities Regulatory Policies Act, Pub. L. No. 95–617, 92 Stat. 3117, 16 U.S.C. 2601, *et seq.*)

In consideration of the foregoing, it is proposed that Subchapter A of Title 18, Code of Federal Regulations, be revised by deleting Part 1b and adding a new Part 1a, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

1. Subchapter A of Title 18, Code of Federal Regulations, is revised by deleting Part 1b and adding a new Part 1a, to read as follows:

PART 1a—RULES RELATING TO INVESTIGATIONS

Sec.

1a.1 Scope and applicability of rules.
1a.2 Requests for investigations.
1a.3 Preliminary investigations.
1a.4 Formal investigations.
1a.5 Subpoenas.
1a.6 Other information-gathering powers during investigations.
1a.7 Sanctions for non-compliance with compulsory process and orders.
1a.8 Transcripts.
1a.9 Rights of witnesses and other persons during investigations.
1a.10 Appearance and practice before the Commission during investigations.
1a.11 Criminal penalties for perjury, subornation of perjury, and false, fictitious or fraudulent statements or entries.
1a.12 Final stages of investigations.
1a.13 Non-public nature of preliminary and formal investigations.
1a.14 Requests for confidential treatment of information.

Authority: Federal Power Act, as amended, 16 U.S.C. 792, *et seq.* Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*, Interstate Commerce Act, as amended, 49 U.S.C. 1, *et seq.*, Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1331, *et seq.*, Mineral Leasing Act of 1920, as amended, 30 U.S.C. 185, *et seq.*, Department of Energy Organization Act, Pub. L. No. 95–91, E.O. 12009, 42 F.R. 46267, Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, Public Utilities Regulatory Policies Act, Pub L. No. 95–617, 92 Stat. 3117, 16 U.S.C. 2601, *et seq.*

§ 1a.1 Scope and applicability of rules.

(a) *Scope.* The Commission, directly or through its staff may conuct investigations under this part relating to any matter subject to its jurisdiction.

(b) *Applicability.* (1) The rules of this part apply to investigations conducted by the Commission or its staff pursuant to section 307 of the Federal Power Act, 16 U.S.C. 825f, section 14 of the Natural Gas Act, 15 U.S.C. 717m, section 12 of the Interstate Commerce Act, 49 U.S.C. 12, sections 501(a) and 508 of the Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, and any other statute administered by the Commission.

(i) To determine whether any person has violated or is about to violate any provision of the Federal Power Act, the Natural Gas Act, the Interstate Commerce Act, the Outer Continental Shelf Lands Act, the Mineral Leasing Act of 1920, the Public Utilities Regulatory Policies Act, the Natural Gas Policy Act of 1978, or the rules, regulations or orders promulgated thereunder;

(ii) To aid in the enforcement of the provisions of those laws, or in prescribing rules and regulations

thereunder, or in obtaining information to serve as a basis for recommending further legislation to the Congress; or

(iii) To verify the accuracy of information received or otherwise to obtain information necessay to perform the Commission's functions.

(2) The rules of this part do not apply to adjudicative or rulemaking proceedings.

§ 1a.2 Requests for investigations.

Any person or entity may request that the Commission commence an investigation. The request should be addressed to Director of the Office of Enforcement, 941 North Capitol Street, N.E., Room 3106, Washington, D.C., 20426. Although the request need not be in any particular form, the request should include a statement of the alleged violation of acts administered by the Commission or the rules, regulations or orders promulgated thereunder, as well as supporting documentation and information. The Commission, the Office of Enforcement, or any member of the Commission's staff designated by the Chairman may initiate an investigation based on such a request, as set forth more fully below in §§ 1a.3 through 1a.14.

§ 1a.3 Preliminary investigations.

(a) *Initiation of preliminary investigations.* A preliminary investigation is generally conducted where it appears from allegations, communications, filings, requests for investigations, or otherwise, that there may be or may have been a violation of the acts, rules, regulations, or orders administered or issued by the Commission. In such preliminary investigations, no compulsory process shall be issued, no testimony shall be compelled, and no oaths shall be administered.

(b) *Persons conducting preliminary investigations.* Preliminary investigations may be conducted by the Commission, by the Office of Enforcement, or by any other member of the Commission's staff designated by the Chairman.

(c) *Procedure after preliminary investigations.* Where it appears from the information obtained during a preliminary investigation that there is a likelihood that a violation may have been committed, is being committed, or may be about to be committed or that the issuance of compulsory process may be appropriate, the staff shall inform the Commission, which may then order a formal investigation, pursue other enforcement alternatives set forth in § 1a.12(b), or take whatever other action it deems necessary or appropriate.

(d) *Non-public nature of preliminary investigations.* Except as provided in § 1a.13 or as otherwise ordered by the Commission, a preliminary investigation is not public. Section 2.72 of this chapter is specifically not applicable to information acquired during preliminary investigations conducted under this part.

(e) *Participation in preliminary investigations.* No person may intervene in any investigation under this section.

§ 1a.4 Formal investigations.

(a) *Initiation of formal investigations.* Only the Commission may initiate a formal investigation. The Commission initiates a formal investigation by issuing an order of investigation.

(b) *Order of investigation.* An order of investigation designates one or more members of the Commission or of the Commission's staff to conduct the formal investigation as officers empowered to administer oaths and affirmations, subpoena witnesses, compel their attendance, take evidence, compel the filing of special reports and interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records which the Commission finds relevant or material to the inquiry or which may lead to information which is relevant or material to the inquiry. An order of investigation shall include:

(1) A general description of the scope of the investigation;

(2) The authority under which the investigation is being conducted; and

(3) A designation of the member or members of the Commission or of the Commission's staff as the officer or officers empowered by the Commission to conduct the investigation, to issue subpoenas, and to compel the production of information.

(c) *Oath.* At the discretion of an officer authorized to conduct the investigation, the statement of a witness may be taken under oath.

(d) *Participation in formal investigations.* No person may intervene in any investigation under this section.

(e) *Non-public nature of formal investigations.* Except as provided in paragraph (f) of this section and § 1a.13, a formal investigation is not public. Section 2.72 of this chapter is specifically not applicable to information acquired during formal investigations conducted under this part.

(f) *Public formal investigations.* A public formal investigation is a formal investigation ordered by the Commission to be conducted, in whole or in part, in public.

(1) *Notice.* The Commission shall issue public notice of its determination to conduct a public formal investigation and, where appropriate, shall advise the public of the time and place of the taking of public testimony of witnesses.

(2) *Applicability of other sections.* The provisions of paragraphs (a), (b), (c) and (d) of this section apply to public formal investigations. Section 2.72 of this chapter is specifically not applicable to information acquired during public formal investigations conducted under this part.

(3) *Termination of public formal investigations.* Whenever the Commission has terminated a public formal investigation of a particular matter and has determined that it will not authorize the commencement of an enforcement action at this time against a particular person named in the formal order of investigation, such person may be advised that the Commission's public formal investigation has been terminated. Such advice shall not be construed as indicating that such person has been exonerated by the Commission, or that no action may ultimately result from the Commission's investigation of the particular matter. Termination of a public formal investigation does not cause the Commission to forego any rights subsequently to bring any action based upon the facts that were the object of the public formal investigation.

(4) *Other procedures.* The Commission may adopt special or additional procedures in connection with any public formal investigation.

§ 1a.5 Subpoenas.

(a) *Issuance of subpoenas.* Any officer authorized to conduct a formal investigation may issue a subpoena directing the person named therein to appear before a designated person at a specified time and place to testify or to produce information, or both, relating to any matter under investigation.

(b) *Service of subpoenas.* Service of subpoenas issued for investigative purposes shall be effected in the following manner:

(1) Delivery of a copy of the subpoena to a natural person may be accomplished:

(i) By handing it to the person;

(ii) By leaving it at his or her office with the person in charge thereof, or, if there is no one in charge, leaving it in a conspicuous place therein;

(iii) By leaving it at his or her dwelling place or usual place of abode with a person of suitable age and discretion then residing therein;

(iv) By mailing it by registered or certified mail to the person at his or her last known address; or

(v) By any method whereby actual notice is given to the person prior to the return date.

(2) Where the person to be served is not a natural person, delivery of a copy of the subpoena may be accomplished:

(i) By handing it to a registered agent for service, or to any officer, director, or agent in charge of any office of such person;

(ii) By mailing it by registered or certified mail to such representative at his or her last known address; or

(iii) By any method whereby actual notice is given to such representative prior to the return date.

(3) Whenever service is to be made upon a person who is represented in the particular pending investigation by an attorney, the service may be made upon the attorney.

(c) *Response to subpoenas.* At the expriation of the time for producing documents subpoenaed in a formal investigation, the subpoenaed person shall submit to the officer issuing the subpoena a written statement under oath declaring, if true, that such person has made or caused to be made a diligent search for the subpoenaed documents and is producing all the documents called for by the subpoena.

(1) If any subpoenaed documents are withheld for any reason, the subpoenaed person:

(i) Shall submit a list of those documents, identifying such documents, if applicable, by date, author, recipient, title, subject matter, and persons receiving copies; and

(ii) Shall, for each withheld document, separately and fully describe the factual and legal basis for its being withheld.

(2) In the event any subpoenaed documents are withheld on a claim of attorney-client privilege, the subpoenaed person shall, for each withheld document, identify the attorney involved, the client involved, the date of the document, and any person who prepared, received, read or examined the document or any copies of drafts thereof.

(d) *Witness fees.* Witnesses appearing pursuant to subpoena shall, upon application, be paid the same fees and mileage expenses that are paid to witnesses in the courts of the United States.

§ 1a.6 Other information-gathering powers during investigations.

(a) *Information-gathering during preliminary investigations.* Information may be obtained through voluntary statements and submissions, through inspections of hydroelectric licensees, public utilities, natural-gas companies, oil pipeline companies or any other persons or entities subject to Commission jurisdiction, and through requests for information.

(b) *Special reports during formal investigations.* Any officer authorized to conduct a formal investigation may, by letter or other written mechanism, require hydroelectric licensees, public utilities, natural-gas companies, or oil pipeline companies to answer under oath in a special report to be filed with the Commission specific questions promulgated by such officer. Such reports shall be made under oath unless the Commission or the officer requiring the special report otherwise specifies. For purposes of this subsection, "special reports" means any report the Commission or its designated officers may order under section 10 of the Natural Gas Act, 15 U.S.C. 717i, section 304 of the Federal Power Act, 16 U.S.C. 825c, section 20(1) of the Interstate Commerce Act, 49 U.S.C. 20(1), or section 508(b) of the Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350.

(c) *Physical inspections during formal investigations.* Information may be obtained during formal investigations through entry and physical inspections of energy facilities and business premises. During such inspections, the Commission or any of its designated officers may:

(1) Inventory and sample any stock of energy resources at such energy facilities and business premises;

(2) Examine and copy any books, records, papers or other documents relating to any such energy information; and

(3) As they deem necessary, question persons under oath or otherwise.

(d) *Other requests for information during formal investigations.* During formal investigations, the Commission or any of its designated officers may require any person who is engaged in the production, refining, transportation by pipeline, sale, or distribution (at other than the retail level) of energy resources to submit, under oath or

otherwise, answers in writing to interrogatories and to requests for reports or for other information. For purposes of this subsection, "report" means any report the Commission may order under section 508(b) of the Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350.

§ 1a.7 Sanctions for noncompliance with compulsory process and orders.

In any case of failure to comply with the compulsory process and orders issued by the Commission or any member of the Commission or its staff during a formal investigation, the Commission may invoke the aid of the appropriate United States District Court or of the Attorney General in seeking enforcement, penalties or criminal sanctions.

§ 1a.8 Transcripts.

Transcripts taken in the course of any investigation under this part shall be recorded solely by an official reporter or by any other person or means authorized by the officer conducting the investigation for the Commission. A person who has provided a statement or testimony in an investigation under this part shall be entitled, upon written request and upon payment of appropriate fees pursuant to § 3.8 of this chapter, to procure a copy of the official transcript of such statement or testimony, except that a witness in a non-public formal investigation may, for good cause, be limited to an inspection only, either in person or by his or her counsel, of the official transcript of such testimony. § 1.21(b) of this chapter is not applicable to investigations under this part.

§ 1a.9 Rights of witnesses and other persons during investigations.

(a) *Access to orders of investigation.* Any person upon whom a subpoena or other compulsory process has been served under this part shall, upon his or her request, be permitted to examine a copy of the Commission's order of investigation. However, a copy of the Commission's order of investigation shall not be furnished for his or her retention unless such retention would be consistent both with the protection of privacy of persons involved in the investigation and with the unimpeded conduct of the investigation.

(b) *Right to counsel.* Subject to the provisions of § 1a.10, any person who appears in person during any investigation may be accompanied, represented and advised only by an attorney who is admitted to practice before the Supreme Court of the United States, the highest court of any State or Territory of the United States or of the District of Columbia, or the District Court of the United States for the District of Columbia.

(1) The right to be accompanied, represented and advised by counsel shall mean the right of a person testifying to have such an attorney present with such person during any formal or preliminary investigation and to have an attorney advise such person during any examination conducted during such investigation. At the conclusion of any such examination, the witness may make a statement on the record to clarify any previous answers or for any other purpose. To aid counsel in protecting the interests of his or her client with respect to any such examination, counsel may take summary notes during the examination.

(2) With due regard for the rights of a witness, the Commission may exclude a particular attorney from further participation in any investigation in which the Commission has found the attorney to have engaged in dilatory, obstructionist or contumacious conduct.

The officer conducting an investigation may report to the Commission any instances of apparently dilatory, obstructionist or contumacious conduct on the part of an attorney during the course of an investigation. The Commission may then take such action as the circumstances warrant including (i) exclusin of the attorney from further participation in the particular investigation or (ii) in accordance with § 1.4(b)(1) of this chapter or § 1100.11 of the Interstate Commerce Act (49 CFR

1100.11), temporary or permanent disqualification from appearance or practice before the Commission.

(c) *Right against self-incrimination; immunity*—(1) *Self-incrimination.* Persons refusing to provide statements, testimony, or documents on the basis of the privilege against self-incrimination in accordance with the Fifth Amendment of the United States Consitution must assert such privilege personally.

(2) *Immunity.* In accordance with 18 U.S.C. 6001, 6002 and 6004, if the Commission believes that the testimony or other information sought to be obtained from any individual may be necessary to the public interest and that individual has refused or is likely to refuse to testify or provide other information on the basis of his or her privilege against self-incrimination, the Commission, with the approval of the Attorney General, may issue an order requiring the individual to give testimony or provide other information which he or she previously refused to give on the basis of his or her privilege against self-incrimination. Whenever a witness refuses, on the basis of his or her privilege against self-incrimination, to testify or provide other information in an investigation under this part, and an officer conducting the investigation communicates to the witness an order issued by the Commission requiring the witness to give testimony or provide other information, the witness may not refuse to comply with the order on the basis of his or her privilege against self-incrimination. However, no testimony or other information compelled under such order (or any information directly or indirectly derived from such testimony or other information) may be used against the witness in any criminal case, except a prosecution for perjury, giving a false statement, or otherwise failing to comply with such order.

(d) *Right to submit statement and other information.* In any investigation under this part, persons may on their own initiative and at any time submit to the officer conducting the investigation any documents, written statements of fact, memoranda of law, or other written information setting forth their interest and position regarding the subject matter of the investigation.

(e) *Sequestration of witnesses.* All witnesses and potential witnesses shall be sequestered and prohibited from being present during the examination of any other witness unless otherwise permitted by the Commission or by the members of the Commission or its staff conducting the preliminary investigation or formal investigation.

§ 1a.10 Appearance and practice before the Commission during investigations.

(a) *Suspension, disbarment or other disciplinary action.* The provisions of § 1.4(b) of this chapter and of § 1100.11 of the Interstate Commerce Commission's regulations (49 CFR 1100.11) are hereby made applicable to all investigations conducted under this part.

(b) *Multiple representation by counsel.* (1) Any counsel representing more than one person in an investigation under this part shall inform the officer conducting the investigation and each client who is a witness of any possible conflict of interest in representing such client. Any counsel appearing with a witness giving testimony on the record shall disclose on the record all the persons that counsel represents in the investigation.

(2) When a reasonable basis exists to believe that an investigation under this part may be obstructed or impeded, directly or indirectly, by an attorney's representation of more than one witness during the course of an investigation, the officer conducting the investigation may prohibit that attorney from being present during the testimony of any other witness in the investigation. To the extent practicable, consistent with the integrity of the investigation, the attorney and the witness will be advised of the reason for such sequestration.

§ 1a.11 Criminal penalties for perjury, subornation of perjury, and false, fictitious, or fraudulent statements or entries.

Any person who willfully states or subscribes under oath any material matter which he or she does not believe to be true or who procures another to commit any perjury during the course of an investigation conducted under this part is subject to criminal penalties for perjury or subornation of perjury, as set forth in 18 U.S.C. 1621 and 1622, respectively. Any person who during the course of any investigation conducted under this part knowingly and willfully falsifies, conceals or covers up by any trick, scheme or device a material fact, or makes any false, fictitious or fraudulent statements or representations, or makes or uses any false writing or document knowing the same to contain false, fictitious or fraudulent statement or entry is subject to criminal penalties, as set forth in 18 U.S.C. 1001.

§ 1a.12 Final stages of investigations.

(a) *Submissions.* (1) The Commission or the officers designated to conduct an investigation, as appropriate, may advise any person involved in the investigation that the Commission is considering commencement of an enforcement action as described in paragraph (b) of this section or that a recommendation for such an enforcement action may be made to the Commission. The Commission or the officers designated to conduct an investigation, as appropriate, may advise any person involved in the investigation of the general nature of the recommendation, including the indicated violations as they pertain to such person and the amount of time available for preparing a written submission.

(2) Any person who has been advised of a potential enforcement action under paragraph (a)(1) of this section may prepare a written statement, with supporting documentation, which sets forth defenses, justifications, excuses, exculpatory material regarding such person's own actions, of inculpatory material regarding the activities of other persons. The submission shall be clearly referenced to the specific investigation to which it relates and shall be submitted to the Commission or the officers designated to conduct the investigation, as appropriate.

(3) If the Commission is conducting the investigation, the Commission shall consider any submission timely made under subparagraph (2) of this paragraph. If the Commission has designated an officer or officers to conduct the investigation, and if such officer or officers determine regarding any particular persons to present to the Commission a recommendation for the commencement of an enforcement action as described in paragraph (b) of this section, then the Commission shall consider any submission timely made by such persons under subparagraph (2) of this paragraph together with the recommendation of the officers conducting the investigation concerning such persons.

(b) *Enforcement alternatives.* After an investigation, the Commission may take one or more of the following actions:

(1) Institution of administrative proceedings;

(2) Institution of civil actions in the courts;

(3) Referral to the Attorney General for criminal prosecution;

(4) Referral to any other governmental authorities; or

(5) Any other appropriate action.

(c) *Policy on consent agreements.* In connection with any decree or sanction to be entered or imposed in any civil lawsuit or administrative proceeding of an accusatory nature brought by the Commission, the Commission will not accept a defendant or respondent to consent to a judgment or order that imposes a sanction while denying allegations contained in the complaint for injunctive relief or the order for administrative proceedings.

§ 1a.13 Nonpublic nature of preliminary and formal investigations.

(a) The existence of any investigation conducted under this part shall not be a matter of public record and any information or documents obtained during the course of any investigation conducted under this part shall not be made publicly available except to the extent that:

(1) The Commission directs or authorizes the public disclosure of the investigation or information;

(2) The information or documents are made a matter of public record; or

(3) Disclosure is required by law.

(b) Notwithstanding paragraph (a) of this section, the Commission and its staff may use any information or documents obtained during the course of an investigation in any manner designed to further the investigation.

(c) A request for confidential treatment of information submitted to the Commission shall not prevent disclosure of information or documents when disclosure is in furtherance of the investigation, of any subsequent enforcement action arising out of the investigation or of any subsequent law enforcement proceeding.

§ 1a.14 Requests for confidential treatment of information.

Any person compelled to produce documents in an investigation may claim that some or all of the information contained in a particular document(s) is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt by law from public disclosure. In such case, the person making such claim shall, at the time said person produces the document to the officer conducting the investigation, also produce a second copy of the document from which the information for which the person claims confidential treatment has been deleted. Said person shall indicate on the original document that a request for confidential treatment is being made for some or all of the information in the document and shall file a statement specifying the statutory justification for non-disclosure of the information for which confidential treatment is claimed. Sufficient information must be furnished for the officer conducting the investigation, or other appropriate official, to make an informed decision on the request for confidential treatment. If the person states that the information comes within the exception in 5 U.S.C. 552(b)(4) for trade secrets and commercial or financial information, the person shall include a statement specifying why the information is privileged or confidential. If the person filing a document does not submit a second copy of the document with the confidential information deleted, the officer conducting the investigation may assume that there is no objection to public disclosure of the document in its entirety. The Commission retains the right to make the determination with regard to any claim of confidentiality. Notice of the decision by the officer conducting the investigation or other appropriate official to deny a claim, in whole or in part, and an opportunity to respond shall be given to a person claiming confidentiality no less than five days before its public disclosure.

¶ 32,014 Transportation Certificate for Natural Gas for the Displacement of Fuel Oil

44 F. R. 21682 (April 11, 1979).

[18 CFR Part 157]

Transportation Certificate for Natural Gas for the Displacement of Fuel Oil

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order commencing rulemaking.

SUMMARY: The Economic Regulatory Administration of the Department of Energy (ERA) has published a proposed rule to encourage and facilitate the issuance by the Commission of one year certificates of public convenience and necessity, under section 7 of the Natural Gas Act. (44 FR 17644, March 22, 1979) By this order, the Commission is establishing a comment procedure on ERA's proposed rule. During the period prior to the adoption of a final rule by the Commission, the Commission will give expeditious consideration to applications which meet the filing requirements stated in ERA's proposed rule.

DATES: Public Hearing on April 30, 1979. Notice of intent to participate in public hearing by April 23, 1979. Submission of statement for presentation of public hearing by April 29, 1979. Written comments filed by April 30, 1979. Final Commission action by May 17, 1979.

ADDRESSES: All filings should reference Docket No. RM79–34 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D C. 20426.

Public hearing location: Address above beginning at 9:30 a.m.

FOR FURTHER INFORMATION CONTACT: Robert C. Platt, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426; 202–275–0161.

SUPPLEMENTARY INFORMATION:

I. Introduction

On March 19, 1979, the Economic Regulatory Administration (ERA) of the Department of Energy proposed a rulemaking to the Commission, pursuant to section 403(a) of the DOE

Organization Act, 42 U.S.C. 7173(a). The ERA Proposed Rule [1] establishes a procedure for the issuance of one year certificates of public convenience and necessity under Section 7(c) of the Natural Gas Act, authorizing the transportation of natural gas purchased by end-users in order to displace fuel oil. In a related rulemaking ERA will establish a procedure to certify the eligibility of end-users for this program. Because ERA finds "an urgent and immediate need to reduce the Nation's reliance on oil imports," and the importance of fashioning a Commission regulation consistent with the overall ERA fule oil displacement effort, the Commission seeks comment upon the ERA Proposed Rule as submitted.

ERA has requested that the Commission place a fuel oil displacement program into effect immediately. As shown in our recent order authorizing the displacement of fuel oil by Consolidated Edison Company of New York, Inc., [2] the Commission is willing to accomodate such efforts under its existing regulations pending final action on the ERA Proposed Rule. Applications conforming to the filing requirements set forth in propose § 157.203 will receive expedited consideration by the Commission during this period.

Section 403(a) of the DOE Organization Act authorizes the Secretary of Energy to propose rules

[1] 144 FR 17644 (March 22, 1979) See ¶ 32,011

[2] Order Granting Declaratory Relief, issued March 16, 1979, Docket Nos. TC79–2 and TC79–3.

with respect to any function within the jurisdiction of the Commission. Section 403(b) of that Act provides that the Commission shall have exclusive jurisdiction over such proposals. Accordingly, although the appended proposal is that of the ERA, the rulemaking proceeding commenced by this order shall result in a final rule of the Commission. The rulemaking proceeding shall be governed by the Commmission's procedures. The comment procedure is established to permit final Commission action on the ERA Proposed Rule by May 17, 1979, the deadline established by the Secretary of Energy pursuant to Section 403(b).

II. Written Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to the ERA Proposed Rule. An original and 14 copies should be filed with the Secrtetary of the Commission. All comments received prior to 4:30 p.m., e.s.t., April 30, 1979, will be considered by the Commission prior to the promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NE., Washington, D.C. during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No RM79–34.

III. Public Hearing Procedures

A public hearing concerning this proposal will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. on April 30, 1979, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written rquest to participate is received by the Secretary of the Commission prior to 4:30 p.m., e.s.t., on April 23, 1979.

Request to participate in the hearing should include a reference to Docket No. RM79–34 as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m. on april 29, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 25 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements.

The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

By the direction of the Commission.

Kenneth F. Plumb,
Secretary.

¶ 32,015 Interconnections of Facilities; Emergencies—Interchange Energy Transmission Rates for Section 202(c) Emergencies

44 F. R. 21683 (April 11, 1979).

[18 CFR Part 32]

Interconnections of Facilities; Emergencies—Interchange Energy Transmission Rates for Section 202(c) Emergencies

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission gives notice of the proposal to repeal 18 CFR 32.62(e) and to set forth a new rate design for sales and transmission services performed pursuant to emergency orders under section 202(c) of the Federal Power Act, including those arising from regional or national fuel shortages for electrical generation. The new rate would be both a model for rate negotiations regarding emergency interconnections ordered by the Economic Regulatory Commission and the effective rate should the parties fail to negotiate a rate. Initial and reply comments are requested and an opportunity for oral presentation is provided. The comment procedures are consolidated with those of Docket No. RM79–29, also published in this issue.

DATES: Initial written comments by May 4, 1979; reply comments by May 21, 1979; requests to speak by April 27, 1979; oral presentations on May 11, 1979, 9:00 a.m.

ADDRESSES: All comments and requests to speak to Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275–4166.

Hearing room location: Hearing Room A, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Robert Cackowski, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275–4777 or Dan Lamke, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275–4233.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is proposing a regulation setting forth an appropriate rate design for sales and transmission services performed during emergencies declared pursuant to section 202(c) of the Federal Power Act including those arising from regional or national fuel shortages for electrical generation. The regulation will be revised as necessary following consideration of comments as provided by this notice.

Section 403(c) of the Department of Energy Organization Act authorizes the Commission to establish rates and charges by rulemaking procedures. The presentation of oral and written views requested by this notice also constitutes the prior hearing required by section 202(c) of the Federal Power Act.

I. Background

Electric utilities have been confronted by two fuel crises of serious proportions during the last six years—the oil embargo of 1973 and coal strike of 1977–78. There is a possibility that a third fuel shortage may result from current uncertainties in the availability and price of oil from many of the nation's traditional foreign suppliers. The industry is increasingly sensitive to geopolitical unrest, labor disputes and other situations which affect the price and availability of an adequate fuel supply for electrical generation. During the two previous periods of fuel inadequacy, the governmental agency having authority to determine that an emergency exists under section 202(c) of the Federal Power Act (FPA), the

Federal Power Commission in 1973 and the Economic Regulatory Administration (ERA) in 1977, did not declare an emergency or order sales to alleviate local or regional shortages.[1] For example, when the New England Power Pool (NEPOOL) filed for emergency relief pursuant to section 202(c) of the FPA during the oil embargo, a settlement was negotiated with most other utility systems and power pools in public conference. *New England Power Pool Participants, et al.*, 52 FPC 410, August 26, 1974. (FPC Docket Nos. RM74–22, E–8589 and E–8850) The settlement rates were the first fuel conservation energy rates to be substituted for then-existing intersystem power rate schedules. The proceeding was an acknowledgement of the need for more specific rate guidelines in emergency situations.

Subsequently, the Commission promulgated § 32.62 of the Regulations describing various ratemaking principles applicable to emergency service ordered pursuant to a section 202(c) application for relief. (Order No. 520—RM75–3 18 CFR 32.60 through 32.62.)

The authority to determine whether a section 202(c) emergency exists and to order emergency transactions was transferred to the ERA pursuant to the Department of Energy Organization Act. However, the commission retains its authority to regulate rates and charges applicable to transactions subject to section 202(c) orders. The Commission now finds it necessary to reform its statement of emergency rate principles. The reasons for the proposed rule are as follows:

(1) The use of existing filed rates which contain components not limited to the actual costs of energy generation and transmission is generally inappropriate during section 202(c) emergencies;

(2) Paragraph (e) of § 32.62 of the Regulations is ambiguous and provides insufficient guidance to the industry concerning the rates that the Commission will set if required to do so when parties fail to agree on a rate during a section 202(c) emergency. It also *encourages* use of rates and charges contained in existing rate schedules during section 202(2) emergencies.

The Commission must be prepared to deal with the fuel inadequacies which are occurring more frequently as the supplies of fossil fuels constrict and political events make their continuous supply more unpredictable. It is important that special rates be designed for extraordinary production and supply problems that are determined to constitute an emergency and that such rates more closely reflect the actual costs of generating and transmitting electricity during those periods.

The proposed regulation prescribes guidelines for a just and reasonable rate for declared emergencies including maximum levels for the adders. This not only has the advantage of limiting prices while allowing utilities to recover out-of-pocket costs plus incidentals and a profit, it adds predictability to the rate structure. The regulation is aimed at discouraging use of ordinary rate designs embodied in filed rate schedules during periods of extraordinary shortages and providing a predictable rate in light of which the parties to an emergency interchange of energy may negotiate the terms of a section 202(c) arrangement. The standard provided by the proposed regulation is an emergency rate design which is intended to permit

[1] Section 202(c) provides:

(c) During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to required by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgement will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

full recovery of quantifiable and unquantifiable costs.

The proposed maximum adders of 2.0 mills/kwh for energy-producing systems and 1.0 mills/kwh for energy transmitters in the proposed rule are nominal amounts which will recover difficult to quantify out-of-pocket costs such as billing and dispatching costs and will compensate for differences between estimated and actual out-of-pocket fuel costs and transmission losses or other incremental costs. The difference between the maximum adder prescribed for transmitters or pass-through systems and that provided for systems which both generate and transmit recognizes that the source systems provide two combined services and thus require additional compensation to recover all out-of-pocket costs.

The coal strike report generally illustrates the relative magnitude of transactions that would be subject to the limitation on adders in the proposed rule. For example, during a one-hour period on February 18, 1978, the abnormally large transactions being used to conserve coal ranged from a low of 19 MW for surplus power to 1200 MW for short-term power.[2] These transactions for the one hour period would produce a maximum revenue from adders alone ranging from $38 to $2400 for the suppliers based on the 2.0 mill/kwh maximum and $19 to $1200 for transmitters or pass-through systems based on the proposed 1.0 mill/kwh maximum. While minimal, such amounts amply and reasonably cover the difficult to quantify out-of-pocket costs for such transactions.

Within the terms of section 202(c), the Commission may determine a reasonable rate when parties to a transaction reach an impasse in establishing an appropriate rate for the ordered transaction. The proposed rate design is both a model for those negotiations and the maximum rate to be prescribed should negotiations not succeed.

Summary

The proposed regulation would provide to electrical utilities a specific guideline regarding rates appropriate to emergency circumstances including emergencies characterized by fuel shortages and escalating prices of particular fuels. For example, utilities in certain regions of the country affected by a shortage of foreign oil that normally is used to generate electricity may find the extensive purchase of electricity a necessity and may petition for emergency relief under section 202(c). Under such circumstances, it is important to restrain the cost of electricity supplied to receiving systems and their customers.

The rate guidelines contained in 18 CFR 32.62(e) conflict with this proposed rule insofar as they fail to articulate the Commission's view on what constitutes a just and reasonable section 202(c) emergency rate. The paragraph is therefore repealed and a new section created to replace it.

The proposed new § 32.63 of the Regulations imposes a basic rate computation method for emergency situations designed to allow recovery of all out-of-pocket costs. It, in effect, sets forth parameters of interchange rates which the Commission will impose if parties do not arrive at a voluntary agreement. Paragraph (c) proposes a fixed monetary limit on charges in addition to total identifiable out-of-pocket costs.

The rate design set forth in this paragraph is to serve as a model for rate agreements negotiated and subsequently filed pursuant to an application for section 202(c) emergency relief or to an ERA declaration of an emergency under the FPA. Paragraph (c) also permits recovery of other costs which may arise during a transaction ordered pursuant to a section 202(c) emergency. Transactions leading to curtailment of

[2] Report of the Designated Officer, Investigation Into Wholesale Power Transactions During Time of Fuel Inadequacies, March 19, 1979 (Docket No. ER78-387) at 8.

sales to the seller's regular wholesale or retail firm customers and resulting in lost revenue or transactions requiring special investment in facilities would require some added compensation for these losses and investments. Such added charges are intended to be strictly cost-based, however. Under the proposed rulemaking, the model rate will not be prescribed where the parties reach an agreement establishing a rate for that particular transaction. The Commission requests comments on whether the model rate set forth in this proposed rulemaking should also be prescribed under sections 205 and 206 of the FPA as the maximum just and reasonable rate to which parties may agree in a section 202(c) emergency.

Written Comment and Reply Procedures and Notice of Oral Presentations

The Commission is consolidating the comment and oral presentation procedures of this Notice with those of the Notice of Proposed Rulemaking Limiting Percentage Adders in Electric Rates (Docket No. RM79-29). Because of the complexity and importance of the issues presented by these rulemakings, the Commission intends that those participating in this proceeding should be able to examine comments of other participants and have an opportunity to respond to the initial comments made in response to these notices. The Commission therefore invites initial written comments no later than 30 days after issuance of this Notice. Reply comments are due 45 days after issuance and should be clearly labeled as such. All comments must be filed with the Office of the Secretary. Initial comments will be available to the public soon after they are received. The opinions of interested parties will be considered by the Commission prior to promulgation of a final regulation.

Comments concerning these regulations may be submitted by writing to Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. All written submissions should contain an original and 18 copies. Reference Docket No. RM79-28. Comments will be placed on file at the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426.

In addition, the Commission will hold a hearing for oral presentation of views on the issues involved in these rulemakings, namely, rates for energy during section 202(c) emergencies and the use of percentage adders. This hearing will be held on May 11, 1979 at the Commission Offices. All persons, including Commission Staff, desiring to be heard at that time should so inform the Office of the Secretary of the Commission by 4:00 p.m. on April 27, 1979 and request presentation time. The Secretary will issue a schedule of presentations on May 4, 1979. Since the time for presentations is limited, the Commission encourages group participation.

In consideration of the foregoing, it is proposed that Part 32, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations, be amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

Part 32, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations, is amended by repealing paragraph 32.62(e) of the Regulations and by establishing § 32.63, relating to rates and charges for use during emergencies declared pursuant to secton 202(c) of the Federal Power Act, to read as follows:

§ 32.62 [Amended]

§ 32.63 Interchange energy rates during Section 202(c) emergencies.

(a) *Applicability.* This section applies to rates to be charged by any public utility, power pool or any other person when providing to other utilities or power pools or other persons service which is ordered during an emergency determined to exist pursuant to section 202(c) of the Federal Power Act.

(b) *Definitions.* For purposes of this section:

(1) "Adder" means any component of a rate which produces revenues in excess of incremental costs.

(2) "Incremental costs" means the sum of identifiable costs incurred in carrying out an order under section 202(c). Such costs include any costs related to fuel, transmission losses, labor, maintenance, gross receipts taxes, start-up, and shut-down.

(c) *General Rule.* If the parties to a transaction ordered under section 202(c) fail to agree on the rate for the transaction, the Commission shall prescribe a rate not to exceed the sum of the following:

(1) Incremental costs;

(2) Adders which do not exceed two (2) mills per kilowatt/hour for any public utility or power pool that is the source of electricity, or one (1) mill per kilowatt/hour for any public utility or power pool which performs only transmitting or pass-through services;

(3) Facilities charges for construction or additions to capacity required by any order issued under section 202(c); and

(4) Net revenues lost by the seller of electric energy due to curtailment of services to firm customers as a direct result of the emergency transaction ordered under section 202(c).

(Federal Power Act, as amended, 16 U.S.C. 792, *et seq.*, Department of Energy Organization Act, Pub. L. No. 95-91, E. O. 12009, 42 FR 46267.)

¶ 32,016 Filing of Rate Schedules—Revisions Limiting Percentage Adders

44 F. R. 21686 (April 11, 1979).

[18 CFR Part 35]

Filing of Rate Schedules—Revisions Limiting Percentage Adders

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Rate schedules currently on file contain percentage adders which cover a variety of miscellaneous costs in electric energy transactions. The Commission is no longer persuaded that some percentage adders used in electric rates are cost-justified. The Federal Energy Regulatory Commission gives notice of a proposal to adopt a regulation which limits the amount of revenue recoverable under percentage adders contained in any rate filed under Part 35 of the Regulations. Initial and reply comments are requested and an opportunity for oral presentation is provided. The comment procedures are consolidated with those of Docket No. RM79–28; also published in this issue.

DATES: Initial written comments by May 4, 1979; reply comments by May 21, 1979; requests to speak by April 27, 1979; oral presentations on May 11, 1979, 9:00 a.m.

ADDRESSES: All comments and requests to speak to Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275–4166.

Hearing room location: Hearing Room A, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Robert Cackowski, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275–4777, or Dan Lamke, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275–4233.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) gives notice that it proposes to adopt a regulation which limits the amount of revenue recoverable under percentage adders included in any rate filed under this Part.

Background

Rate schedules currently on file contain percentage adders which cover a variety of miscellaneous costs in electric energy transactions. The Commission is no longer persuaded that some percentage adders used in electric rates are cost-justified. Percentage adders appear to be unjustified to the extent that indirect costs intended to be recovered by these adders do not increase proportionately with out-of-pocket costs. This is especially true in multiple party transactions where each generating or transmitting utility adds its charge, usually 10 percent of out-of-pocket costs to the utility, for unspecified and miscellaneous administrative costs. The final charge for the electricity thus may bear little relation to the actual costs of producing the electricity and transferring it to a receiving system.

The average cost of oil-fired electrical generation rose from $0.70/mBtu at the beginning of 1973 to $2.08/mBtu in July 1978, with a peak of $2.30/mBtu in 1977.[1] Since 1973, the increase in the cost of fuel has been greater than increases for other components of cost. This great inflation in fuel costs since 1973 has increased percentage adders because such adders operate as a function of out-

[1] Report of Designated Officer, Investigation Into Wholesale Power Transactions During Time of Fuel Inadequacies, March 19, 1979 (Docket No. ER78–367) Appendix I at 9. The discussion of adders is found on pages 11–14 and Appendix I, pages 7–13.

of-pocket cost (primarily fuel costs) under all circumstances. This phenomenon calls into question whether rates with such adders are just and reasonable. Therefore, it is necessary to address the adders included in any electic rate in order to prevent miscellaneous charges from escalating without relation to the kinds of actual costs they are intended to defray. Proposed section 35.23 is an attempt to deal with this problem.

Generally, the principal specific and identifiable costs are included in out-of-pocket costs. Percentage adders in filed rates have been defended on the grounds that they recover incidental miscellaneous expenses, ensure that sellers are adequately compensated for costs in the event that costs were underestimated, and provide an incentive to prospective sellers to engage in the desired transaction. However, the increases in fuel prices have tended to make this rate component inordinately large. Prior to 1973, 10 percent adders rarely produced more than $1.5/mwh, but today they may produce $5/mwh or more, particularly when more than two systems are involved in the transaction.[2] The coal strike experience is instructive. During the strike, the percentage adders in the filed rates contributed substantially to the high costs paid by receiving systems. Power was frequently generated from high-cost oil-fired units and resold through multiple systems. Fuel conservation rate schedules, which did not contain percentage adders in the transmission rates, were not utilized and adders billed under the short-term and emergency service schedules produced income for all the sellers in the chain far in excess of incremental costs. Therefore, percentage adders to the out-of-pocket cost of interchange energy are difficult to justify, particularly in light of escalating fuel costs and the probably increasing frequency of multiple interconnections.

The proposed maximum adders of 2.0 mills/kwh and 1.0 mills/kwh in the proposed rule are nominal amounts which will recover difficult to quantify out-of-pocket costs such as billing and dispatching costs and are intended to compensate for errors in estimating out-of-pocket fuel costs and transmission losses or other incremental costs. The difference between the maximum adder prescribed for transmitters or pass-through systems and that provided for systems which both generate and transmit recognizes that the source systems provide two combined services and thus require additional compensation to recover all out-of-pocket costs.

The coal strike report generally illustrates the relative magnitude of transactions that would be subject to the limitations on adders in the proposed rule. For example, during a one-hour period on February 18, 1978, the abnormally large transactions being used to conserve coal ranged from a low of 19 MW for surplus power to 1200 MW for short-term power.[3] These transactions for the one hour period would produce a maximum revenue ranging from $38 to $2400 for the 2.0 mill/kwh maximum and $19 to $1200 for transmitters or pass-through systems based on the proposed 1.0 mill/kwh maximum. While minimal, such amounts amply and reasonably cover the difficult to quantify out-of-pocket costs for such transactions.

The Commission recognizes that a cost control problem may also exist with respect to other rate components. For example, split-savings adders may now be greater in magnitude than before 1973 because of the growing difference in the cost of coal-fired and oil-fired electrical generation. The difference between the cost per mBtu of oil-generated electricity and the like cost of coal-generated electricity better than tripled between early 1973 and late 1977. As oil-fired utilities seek to conserve fuel and reduce costs by purchasing coal-generated energy, the seller in an economy energy transaction receives 50 percent of the difference between its

[2] *Id.* at Appendix I, page 12.

[3] *Id.* at 8.

incremental costs and the buyer's decremental costs. The coal strike report finds that adders are probably a larger proportion of the economy energy rates than they were in 1973 and revenues recovered under them have actually increased faster then the out-of-pocket cost of fuel.[4] Other problems may exist with respect to reservation charges in the context of fuel conservation rates filed during the coal strike and subsequently suspended.[5]

The prospect of further oil price increases as well as other considerations make it imperative that a concerted effort be made to find workable solutions to these unresolved rate problems. In the meantime, the Commission encourages the filing of rate schedules incorporating rates similar to those rates proposed under the accompanying proposed regulation (Docket No. RM79–28), for use in non-emergency multiple interchange transactions and where there is a large gap between the cost of available fuels in such transactions, instead of economy energy rates with split-savings adders.

The Commission finds that percentage adders in filed rates are unjust and unreasonable in many circumstances.

The coal strike report confirms that such rate components tend to undermine the cost relation of electric rates, especially in multiple interchange transactions and during periods of escalating fuel costs. The Commission therefore proposes to establish a just and reasonable rate pursuant to its authority under section 206(a) of the Federal Power Act. This ratemaking is to be accomplished by rule under section 403 of the Department of Energy Organization Act.

Summary

The proposed regulation requires that all percentage adders in filed electric rates be confined within limits. Utilities would be required to revise the adder portions of rate schedules currently filed under 18 CFR Part 35 and to cap all percentage adders in rates filed in the future consistent with this proposed rule.

Subparagraph 35.23(d) provides that electric rates shall not contain adders that recover more than two mills per kilowatt/hour for the utilities generating the electricity or more than one mill per kilowatt/hour for utilities which only transmit the electricity. Adders may be computed as percentages of incremental or out-of-pocket costs but may not exceed the specified levels for each transaction. Adder portions of rate schedules now on file would be required to be revised to reflect these limits by the effective date of a final rule. The revised rates would become effective five days after the effective date of the proposed rule, but would be subject to review for compliance with the proposed rule. This proposed rule does not inhibit the use of adders not computed as a percentage of out-of-pocket costs. Fixed adders in excess of the limits set forth in the proposed rule would, of course, have to be cost-justified.

Written Comment and Reply Procedures and Notice of Oral Presentation

The Commission is consolidating the comment and oral presentation procedures of this Notice and those of the Notice of Proposed Rulemaking Governing Interchange Energy Rates During Section 202(c) Emergencies (Docket No. RM79–28). Because of the complexity and importance of the issues presented by these rulemakings, the Commission intends that those participating in this proceeding should be able to examine the comments of other participants and have an opportunity to respond to the initial comments made in response to these notices. The Commission therefore invites initial written comments no later than 30 days after issuance of this Notice. Reply comments are due 45 days

[4] *Id.* at 11.

[5] Proceedings to consider several fuel conservation energy rates, suspended by the Commission orders, are pending in Docket Nos. ER78–107, ER78–108, ER78–109, ER78–219, ER78–229, ER78–249, ER78–252, ER78–292, and ER78–313. (Orders issued between February 13, 1978 and May 28, 1978.)

after issuance and should be clearly labeled as such. All comments must be filed with the Office of the Secretary. Initial comments will be available to the public soon after they are received. The opinions of interested parties will be considered by the Commission prior to promulgation of a final regulation.

Comments concerning these regulations may be submitted by writing to Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. All written submissions should contain an original and 18 copies. Reference Docket No. RM79–29. Comments will be placed on file at the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426.

In addition, the Commission will hold a hearing for oral presentation of views on the issues involved in these rulemakings, namely rates for energy during section 202(c) emergencies and the use of percentage adders. This hearing will be held on May 11, 1979 at the Commission Offices. All persons, including Commission Staff, desiring to be heard at that time should so inform the Office of the Secretary of the Commission at (202) 275–4166 by 4:00 p.m. on April 27, 1979 and request presentation time. The Secretary will issue a schedule of presentations on May 4, 1979. Since the time for presentations is limited, the Commission encourages group participation.

(Federal Power Act, as amended, 16 U.S.C. 792, *et seq.*, Department of Energy Organization Act, Pub. L. 95–91, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing it is proposed that Part 35, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations, be amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

Part 35, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations, is amended by adding § 35.23 to read as follows:

§ 35.23 Limits on percentage adders; revision of rate schedules.

(a) *Applicability.* This section applies to all electric rates which are filed or which are required to be filed under this part of the Commission's Regulations.

(b) *Definitions.* For purposes of this section, "percentage adder" means any component of a rate under which component revenues are determined as a percentage of the sum of incremental or out-of-pocket costs related to fuel, transmission losses, labor, maintenance, gross receipts taxes, start-up, and shut-down.

(c) *General rule.* In any transaction, no percentage adders may result in an amount of revenue which exceeds:

(1) Two (2) mills per kilowatt/hour for any utility which in the source of the electricity; or

(2) One (1) mill per kilowatt/hour for any utility which performs only transmitting or pass-through services.

(d) Each public utility:

(1) Shall revise any rate schedule and tariff filed unde this part, to limit any percentage adders in accordance with paragraph (c) of this section; and

(2) Shall file any other rate or rate change under this part after the date of this section in compliance with paragraph (c) of this section.

(e) All rate schedules required to be revised by this section shall be filed no later than the effective date of this regulation, and shall be effective five (5) days thereafter, subject to subsequent review for compliance with paragraph (c) of this section.

¶ 32,017 Determination of Incentive Rate of Return, Tariff, and Related Issues for the Alaska Natural Gas Transportation System

44 F. R. 22090 (April 13, 1979).

[18 CFR Chapter I]

Determination of Incentive Rate of Return, Tariff, and Related Issues for the Alaska Natural Gas Transportation System

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (the Commission) hereby gives notice of a proposal to establish values for the Incentive Rate of Return (IROR) mechanism appended to the terms and conditions of the conditional certificates of public convenience and necessity previously issued in the Alaska Natural Gas Transportation System proceedings (Docket Nos. CP78–123, CP78–124, CP78–125 and RM78–12). In addition to proposing values for the IROR, the Notice proposes to establish adjustment methods to be used in applying the IROR. These methods include adjustment for inflation and adjustments for incidents beyond the control of project sponsors (change-in-scope). The result would be an incentive rate of return on equity to reward the applicants for final certificates for project completion under budgeted cost and penalize them for project completion over budgeted cost. In that the tariffs filed by the sponsors directly impact the IROR, the Notice also provides for comment on these tariffs.

DATES: Notice of intent to participate by April 16, 1979. Written comments by May 4, 1979. Reply comments by May 16, 1979.

ADDRESS: All filings should reference Docket No. RM78–12 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: John Adger, Director, Alaska Natural Gas Project Office, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275–3827.

SUPPLEMENTARY INFORMATION:

I. Background:
A. Scope of proceeding.
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Terms and Conditions

App. A—"Project Risk Premium."
App. B—Petition of Alaskan Northwest Natural Gas Transportation Co.

By this Notice, the Federal energy Regulatory Commission (Commission) inaugurates a proceeding to resolve outstanding issues concerning the imposition of an Incentive Rate of Return (IROR) mechanism upon the Alaskan and Northern Border segments

of the alaskan Natural Gas Transportation System (ANGTS).[1] In addition, this proceeding will also resolve certain issues attendant to the Commission's adoption of the tariffs submitted by the Alaskan Northwest Pipeline Company (Alaskan Northwest) and the Northern Border Pipeline Company (Northern Border), the respective sponsors of the alaskan and Northern Border segments of the ANGTS.[2] The use of rulemaking procedures to consider IROR and related tariff issues follows the recommendations made to the Commission by its Alaskan Delegate.[3] In addition to other applicable law, this proceeding is undertaken pursuant to section 7 of the Natural Gas Act, 15 U.S.C. § 717f, section 9 of the Alaska Natural Gas Transportation Act, 15 U.S.C. § 719g, and sections 402(a), 402(e), and 403(c) of the Department of Energy Organization Act, 42 U.S.C. §§ 7172(a), (e), 7173(c).

I. Background

A. Scope of proceeding

The implementation of an IROR mechanism on the Alaskan and Northern Border segments of the ANGTS left three important issues unresolved: the values to be assigned to the various components of the mechanism; the breadth of procedures to adjust cost and scheduling estimates for events not anticipated in designing the system and planning its construction (change-in-scope issues); and the mechanism(s) to adjust costs of construction for inflation.[4] The purpose of this proceeding is to resolve these three outstanding issues.

The assignment of values to the IROR mechanism entails determinations of a "Marginal Rate," "Center Rate," "Non-Incentive Rate," and "Center Point" for both the Alaskan and Northern Border Segments.[5] In turn, these values depend upon the determination of an "Operation Phase Rate"[6] and a "project Risk Premium".[7] The "Operation Phase Rate" is affected by the form and terms of tariffs covering the operation of the separate segments.[8,9]

Approval of the initial tariffs filed by Alaskan Northwest and Northern Border will, but for the single issue of depreciation for the Northern Border segment as filed in Northern Border's tariff, be resolved within this proceeding. The depreciation rate for the Alaska segment will be considered as part of this rulemaking. The distinction arises because the "pre-built" facilities proposed for Northern Border are based on deliveries of both Alaskan gas and supplies from Canada. Given the difference in volumes and the facilities that may be necessary from those considered in the *Decision*, a question arises with respect to depreciation of the Northern Border segment. The depreciation of the Alaska segment was addressed before the FPC in Docket Nos. CP75–96, *et al.* Persons seeking to modify that assessment bear the burden of proving the need for a change. This record, however, is not currently available for Northern Border.

[1] In prior proceedings, the Commission attached incentive rate of return conditions to the conditional certificates of public convenience and necessity issued to the Alaskan Northwest Pipeline Company and the Northern Border Pipeline Company. Order No. 17, Docket No. RM78–12 (Dec. 1, 1978), *confirmed*, Order No. 17–A, Docket No. RM78–12 (Jan. 12, 1979). By these orders the Commission imposed upon the named parties, and the components of the ANGTS for which they were responsible, an IROR mechanism, and left to further proceedings the determination of actual values for implementing that mechanism. Order No. 17 at 6, 9–10; Order 17–A at 4–7.

[2] The tariffs of the two sponsors were submitted pursuant to Commission order of february 22, 1979. Notice of Delegate Report and Order Directing Tariff Filing, Docket No. RM78–12 (Feb. 22, 1979).

[3] Memorandum to the Commission, appended to the above-cited Order Directing Tariff filing, Feb. 22, 1979 [hereinafter cited as Delegate's memorandum].

[4] Order No. 17 at 2, 6, and 9. In addition, the cost format which the sponsors were to follow in their submissions of Certificate Cost and Schedule Estimates as well as the procedures to implement these estimates were left for future determination. *Id.* at 9.

[5] Order No. 17 at 10. For definitions of these and related terms, see Order No. 17 at 20–22.

[6] *Id.* at 10; Order No. 17–A at 6.

[7] Order No. 17-A at 7.

[8] Order No. 17 at 10; Order No. 17-A at 6–7; *see*, on the relationship of tariff to IROR issues, Section V, *infra; see also* Order No. 17 at 10.

[9] *See, e.g.*, Report of the Alaskan Delegate on Tariff and Operation Phase Rate Issues, accompanying Delegate's Memorandum, note 3 *supra*.

The Northern Border depreciation issue will be incorporated in the on-the-record hearing proceeding to be convened to resolve those issues arising from the certification of the "pre-built" sections of the ANGTS (Docket Nos. CP78–123, *et al.*). There are two reasons for resolving the depreciation issue within the context of the adjudicatory proceeding rather than this rulemaking. First, the conferences held to discuss advanced delivery issues (*In re* Alaskan Natural Gas Transportation System—Conference on Advanced Delivery Project, Docket Nos. CP78–123 *et al.*) show that this issue requires full adjudicatory proceedings for its resolution. Second, the issue is intimately connected with other issues surrounding the certification of the pre-built segments, for example, the lengths of the gas sales contracts, the size and capacity of the proposed facilities and the financing feasibility. The Commission will address the other issues to be heard in the on-the-record proceeding in an order in Docket No. CP78–123, *et al.*

The determination of the change-in-scope issue has always been perceived to be of critical importance to the implementation of an IROR mechanism.[10] This issue was separated from the Incentive Rate of Return Rulemaking of Docket RM78–12 and deferred to a later but undesignated rulemaking.[11] However, in that the change-in-scope issue and the procedures for its implementation during and after construction are so intertwined with rate or return questions, change-in-scope questions must be resolved as a part ofthe IROR. For this reason it is included in this rulemaking.

The application of an IROR mechanism must also provide for cost increases due to inflationary pressures.[12] Deflating actual costs to base-year prices becomes necessary to determine the effect of an IROR. Therefore, the inflation adjustment will also be included in this rulemaking.

B. Procedures

In Order Nos. 17 and 17–A, the Commission described alternative procedures for the consideration and resolution of the complex issues involved in the implementation of an IROR mechanism. For example, while the values of the rates of return and risk premiums were to be determined by evidentiary proceedings (Order No. 17 at 2), other issues such as change-in-scope and the determination of the "Operation Phase Rate" were to be addressed thrugh rulemakings (*id.* at 6. 7). The Delegate was directed to develop a comprehensive procedure for the prompt resolution of the issues surrounding the IROR mechanism.[13]

In a mermorandum to the Commission, the Alaskan Delegate recommended that:

> * * * consideration of as many of the remaining IROR issues as possible be consolidated into a single "rulemaking" type of proceeding to be intiated as soon as possible after March 1, 1979. As the project company tariffs for Northern Border and the Alaska segment should be filed at about the same time, consideration of the tariffs and their respective Operation Phase Rates could also be consolidated into one master proceeding to resolve essentially all the remaining IROR issues based upon some basic assumptions about the sponsors' financing plans. (Delegate's Memorandum at 3)

A predicate to this recommendation is that the unresolved issues concerning the IROR and the tariffs are so interrelated that their concurrent consideration, if not required, is at least expedient.

In its February 22, 1979 order directing that tariffs be filed by Alaskan Northwest and Northern Border, the

[10] *See, e.g.*, Notice of Proposed Rulemaking, Incentive Rate of Return for the Alaska Natural Gas Transportation System, docket RM78–12, at 3 (May 8, 1978); *see also* Order No. 17 at 6.

[11] Revised Notice of Proposed Rulemaking, Incentive Rate of Return for the Alaska Natural Gas Transportation System, Docket No. RM78–12, at 6 (Sept. 15, 1978).

[12] *Id.* at 49–53

[13] Order No. 17 at 9–10; Order No. 17–A at 6–7.

Commission concurred in the Delegate's recommendation that the IROR and related tariff issues be settled in a single proceeding. Upon further consideration of this recommendation, and after reviewing the comments submitted in response to the Alaskan Delegate's suggested procedure,[14] the Commission finds the Delegate's proposal to be well suited to the expeditious and efficient resolution of outstanding IROR and related tariff issues.

Legal and practical considerations necessitate an expeditious resolution of IROR and tariff issues. Under section 9 of the Alaska Natural Gas Transportation Act of 1976 (ANGTA), Pub. L. No. 94–586, 90 Stat. 2912 (15 U.S.C. § 719g), the Commission must, to the fullest extent permitted by applicable provisions of law, issue required certificates and authorizations for the ANGTS "at the earliest practicable date." 15 U.S.C. § 719g(b). Since the IROR mechanism is noted in the conditional certificates of Alaskan Northwest and Northern Border as a matter still to be resolved, the conclusion of outstanding IROR issues comes within the purview of section 9 of ANGTS. For similar reasons, the approval of tariffs for the Alaska and Northern Border segments must also be expedited. 15 U.S.C. § 719g(b).[15]

It is the Commission's view that the use of informal rulemaking procedures provides the means to resolve these issues quickly. Comments and reply comments, quite apart from their function to provide necessary information for informed decisionmaking,[16] can serve to simplify proceedings by isolating particular issues. In addition, the resolution or isolation of issues can proceed at a much faster pace through recourse to notice and comment procedures than through the more formal adjudicatory process.

The Commission's use of rulemaking procedures to determine rates under the Natural Gas Act is well established at law.[17] However, as the State of Alaska pointed out in its comments on the Alaskan Delegate's procedural recommendation, the use of such procedures is not without some limits. In using a rulemaking procedure to set rates the Commission must assure that there is consideration of all issues and full opportunity for interested persons to present their views.[18]

In addition to the notice and comment procedure afforded to interested parties as a matter of course, this proceeding will also afford interested parties an opportunity to submit reply comments and to petition for oral argument to address issues deemed by a party to be of sufficient weight and controversy as to warrant additional attention. It is the Commission's view that comment, reply comment, and opportunity for oral argument complies with both section 403(c) of the DOE Act and section 7 of the Natural Gas Act. The Commission may institute such other procedures if, in its discretion, it deems them appropriate to insure full consideration of the issues.

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[14] Five parties expressed their views in response to the Commission's request for comments on the procedure recommended by the Delegate. Three, the State of Alaska, the Public Service Commission of New York, and Commission Staff, filed formal comments; the other two, Alaskan Northwest and Northern Border, submitted theirs as a part of their tariff filings.

[15] *See, e.g.*, Alaskan Northwest, Petition for Expedited Rulemaking and Issuance of Final Order Establishing Rate of Return Range, Docket No. RM78–12 (filed Feb. 15, 1979).

[16] *See e.g., Union Oil Co. of California* v. *FPC*, 542 F.2d 1036, 1041 (9th Cir. 1976); *see, generally* 1 K. Davis, Administrative Law Treatise 539–542 (2nd ed. 1978).

[17] *See e.g., American Public Gas Ass'n* v. *FPC* (The Second National Natural Gas Rate Cases) 567 F.2d 1016 (D.C. Cir. 1977) *cert. denied* 435 U.S. 907 (1978); *Shell Oil Co.* v. *FPC*, 520 F.2d 1061 (5th Cir. 1975), *cert. denied* 426 U.S. 941 (1976). *Phillips Petroleum Co.* v. *FPC*, 475 F.2d 842 (10th Cir. 1973), *cert. denied*, 414 U.S. 1148 (1974); *see also* section 403(c) of the Department of Energy Organization Act, Pub. L. No. 95–91, 91 Stat. 585 (42 U.S.C. § 7173(c)) (hereinafter referred to as DOE Act).

[18] 42 U.S.C. § 7173(c); *see also* Joint Explanatory Statement of the Committee on Conference, DOE Act, 95th Cong., 1st Sess., S. Rept. No. 95–367, at 77.

C. Comments

Five comments were received on the Alaskan Delegate's recommended procedure. (*See* note 15, *supra.*) Two commentors, Alaskan Northwest and Northern Border, generally supported the concept of a single rulemaking procedure to settle both IROR and tariff issues. Two, those of the State of Alaska and the Public Service Commission of the State of New York, were opposed to the proposed procedures. The fifth, submitted by Commission Staff, although not objecting to the procedure, joined with the State of Alaska and the Public Service Commission of New York, in expressing reservations about the scope of the proceeding with respect to tariff issues.

The comments which supported the proposed rulemaking procedure cited the expediency of eliminating cross-examination of witnesses and oral argument. They split, however, on the scope of issues which could be explored within a single proceeding. Northern Border suggested that in addition to issues involving IROR and related tariff matters of the sponsors, the proceeding should be broadened to include issues concerning cost recovery by shippers. In Northern Border's view, it is necessary to give each shipper assurance that there will be an automatic cost recovery of all amounts paid under the Northern Border tariff.

Alaskan Northwest, citing the difficulty involved in establishing certification cost estimates, noted that the goal of resolving all remaining issues associated with the IROR mechanism in one rulemaking prior to May 15, 1979, was at best elusive.[19] For this reason Alaskan Northwest suggested that definitive action could be taken by the Commission through consideration of the sponsor's petition requesting the establishment of a "zone of a reasonableness" for the rate of return applicable to the Alaskan project. (Petition for Expedited Rulemaking and Issuance of Final Order Establishing Rate of Return Range, Docket No. RM78-12 (filed February 15, 1979).)

Expanding the scope of this proceeding to encompass considerations of shippers' tariffs, as suggested by Northern Border, would only add to the complexity of the proceeding without providing compensatory benefits. Limiting the proceeding to considerations of ranges of return, as suggested by Alaskan Northwest, would accomplish too little.

The concern of Alaskan Northwest with certificate cost estimates and their impact on the determination of IROR issues, is, we believe, misplaced. As described more fully below, the estimates need not be precisely known to gauge the impact of the IROR mechanism. Moreover, the concept advanced by Alaskan Northwest to establish an *a priori* "zone of reasonableness" for rates of return can be addressed within the context of this proceeding.[20] Given the expedited procedures involved and the cooperation of all participants, the IROR issues should be resolved in time to permit investment for the scheduled startup and completion of the project.

Among the concerns expressed in the comments by the State of Alaska and the New York Public Service Commission were doubts as to the propriety of resolving tariff and rate issues by rulemaking. The New York Public Service Commission focused upon the determination of the equity portion of the overall return for the Alaskan and Northern Border segments of ANGTS to which the IROR will apply. In its opinion this determination could not and should not be made on the basis of written pleadings and submittals. The

[19] The basis for this opinion was that the Certification Cost Estimate, used to establish the "Center Point" and the "Cost Performance Ratio" was dependent upon such determinations as the proximity of the gas pipeline to the oil pipeline, the maximum allowable operating pressure, and the application of environmental and other stipulations, factors recognized in Order No. 17. In addition, Alaskan Northwest cited the language of that Order that the cost estimates will not be known with any degree of precision for "some months hence." Order No. 17 at 7.

[20] See Section II(B), *infra.*

State of Alaska, while not taking issue with the use of rulemaking procedures to resolve change-in-scope and inflation adjustment issues, expressed concern with the procedural unfairness of establishing rates or tariffs without an opportunity for cross examination. In support of this view, Alaska stated that the nature of the factual determinations to be made with regard to the tariffs and setting the IROR were one traditionally and properly addressed in evidentiary hearings.

As discussed above, we are of the opinion that the procedures to be used in this rulemaking will suffice to protect the interests of all concerned while providing the Commission with information necessary for a prompt resolution of the issues involved. The procedure to be used was designed to be expeditious.

With respect to the scope of the proceedings, the State of Alaska thought that the Delegate's recommendation was a limited one, utilizing rulemaking procedures to settle only IROR issues while the Commission's order of February 22, 1979 expressed a broader (and therefore inconsistent) view, that the proceeding would encompass both IROR and related tariff issues. In addition, the State of Alaska requested a precise definition of which tariff issues would be involved in the rulemaking proceeding. The language of the Delegate's Momorandum comports with that of the Commission in recommending a broad proceeding to settle IROR and tariff issues. As described above, all tariff issues except those involving depreciation in the Northern Border tariff will be considered in this rulemaking.

The Commission Staff expressed concern as to the procedural relationship of tariff and IROR issues and the proceedings involving pre-built construction (Docket No. CP78-123, *et al.*). Further, Staff (1) recommended that tariff issues be settled before IROR issues; and (2) suggested that issues raised by the Delegate's Report provided for unnecessary procedures to the extent that the issues may already have been decided by the President's *Decision and Report to Congress on the Alaskan Natural Gas Transportation System (Decision)*. Both of these concerns are met in the procedures of this rulemaking. As explained more fully below,[21] the tariffs submitted by Northern Border and Northwest Alaskan are to be considered in this rulemaking and the two sponsors are to bear the burden of showing that their respective tariffs are consistent with the President's *Decision* and otherwise required in the public convenience and necessity under the Natural Gas Act.

II. The IROR Schedule

A. Overview and Interrelationships

An IROR mechanism is defined by three factors: a "Center Rate of Return", a "Center Point" and a "Marginal Rate of Return". Given these three factors, an IROR schedule—a table or formula—can be structured to establish a value for the IROR for any level of expenditure in constructing the pipeline. The relation of the level of expenditure to the IROR schedule is computed through a "cost performance ratio", the ratio of "Actual Capital Costs" incurred during construction to the "Projected Capital Costs".

The "Center Rate of Return", which is the rate of return allowed if the actual construction costs equal the expected construction costs, is a rate of return composed of the sum of (1) an "Operation Phase Rate of Return", (2) a "Project Risk Premium" (to provide compensation for any unusual financial risks borne by equity investors during construction),[22] and (3) an "IROR Risk Premium" (to provide compensation for financial risks created by any IROR mechanism).

The Operation Phase Rate of Return is to compensate equity investors for risks

[21] See Section V, *infra*.

[22] The addition of the "Project Risk Premium" yields a "Non-Incentive Rate of Return."

incurred during pipeline operation; it is not to provide compensation for risks incurred during construction. (Compensation for risks incurred during construction is provided through the addition of the Project Risk and IROR Risk premiums.) Since the Operation Phase Rate involves the operation of the pipeline and the risks attendant to that operation, any determination of an Operation Phase Rate rests upon tariffs filed with and approved by the Commission.

The Center Point is that value of the Cost Performance Ratio which would be achieved at the expected or most likely level of construction costs. The Center Point should be a measure of the mean costs for which the project sponsors are to be held responsible. Therefore, the definition of which costs the sponsors are *not* responsible for—the "Change-in-Scope" procedure—is a key element in determining the Center Point.

The Marginal Rate of Return is the rate of return earned on each additional or incremental dollar of capital invested in construction cost overrun. It is the rate which provides the incentive to minimize cost overruns.

The Cost Performance Ratio is the main factor which relates the IROR schedule to the particular construction costs of the pipeline. If Actual Costs are equal to Projected Capital Costs, the ratio would yield an IROR equal to the Center Rate of Return.[23] To the extent that the actual costs are less than estimated costs, the IROR would be greater than the Center Rate of Return; but how much greater depends upon (1) the ratio and (2) the Marginal Rate. However, should actual costs be greater than estimated costs, an increase in the Cost Performance Ratio results and the IROR falls below the Center Rate of Return; how much below depends, again, on the ratio and the Marginal Rate.

The calculation of the Cost Performance Ratio depends on two figures: the actual cost to construct the pipeline and the estimated cost to construct the pipeline. In establishing the IROR mechanism, the Commission adopted the view that project sponsors should not be penalized for certain types or categories of cost increases. Consequently, the Commission has adopted the concept that the estimated costs should be modified to reflect cost increases resulting from general inflation or certain enumerated circumstances. The former is termed the Inflation Adjustment; the latter the Change-in-Scope Mechanism.

B. Basic Components

1. Center Rate of Return.—The Center Rate of Return is composed of the Operation Phase Rate, a Project Risk Premium, and an IROR Risk Premium. The Commission proposes that the Center Rate of Return for the Alaskan Segment be set at 17.5% and that the Center Rate of Return for the Northern Border be set at 15.25%. The computation of these two figures is discussed below.[24]

[23] Normally, where Actual Costs equal Projected Costs the ratio is 1/1 or 1.0. For reasons described below, this is not the ratio proposed by the Commission for receipt of the "Center Rate of Return". *See* Section II(B)(2), *infra*.

[24] In the course of preparing for this proceeding, the Commission, through the Alaska Delegate, received several reports and study papers produced by outside individuals, some of whom are party to this case. All of these reports were served on interested parties of record and are hereby incorporated into the record of this proceeding. These reports do not necessarily represent the opinion of the Commission; they are merely in the nature of "preliminary comments". The reports received are: Alaska Gas Project Office, FERC, "Price Indices for Adjusting the Cost Performance Ratio of the Alaska Gas Pipeline: Analysis and Recommendations" (March 29, 1979) [hereinafter cited as Alaska Gas Project Office Report]; Jerome E. Haas, "Risk, Return and the IROR Plan: A Report to the Federal Energy Regulatory Commission" (March 1979) [hereinafter cited as Haas Report]; James D. McCullough, Institute for Defense Analysis, "On the Treatment of Risk and Uncertainty in Determining Change in Scope Allowability and Center Point Establishment in the Alaska Gas Pipeline IROR Mechanism" (March 1979) [hereinafter cited as McCullough Report]; Northwest Alaskan Pipeline Company, "Allowable Cost Estimate Revisions Under the Incentive Rate of Return" Procedure (March 3, 1979) [hereinafter cited as Northwest Alaskan, "Allowable Cost Estimate Revisions"]; Northwest Alaskan Pipeline Company, "Determining the Project Risk Premium for the Alaska Segment of the Alaska Natural Gas Transportation System" (March 7, 1979) [hereinafter cited as Northwest Alaskan, "Determining Project Risk Premium"]; Northwest Alaskan Pipeline Company, "Recommended Inflation Adjustment Under the Incentive Rate of Return (IROR) Procedure" (March 7, 1979) [hereinafter cited as Northwest Alaska "Recommended Inflation Adjustment"].

a. Operation Phase Rate. The Operation Phase Rate is intended to compensate equity investors for risks normally expected to be incurred during operation of the pipeline. Through this proceeding, the Operation Phase Rate will be determined for both the Alaskan and Northern Border segments. The issues surrounding the setting of the Operation Phase Rate for these two segments, including project risk, cost changes, throughput changes, service interruption, marketability, and equity capitalization, were set out and discussed in the "Delegate Report" released February 22, 1979.[25]

In that Report, the Delegate compared the risks borne by investors during the operation of the Alaska gas pipeline to the risks borne by investors in a conventional or typical lower-48 states' natural gas pipeline. Further, the comments submitted pursuant to the September 15, 1978 Notice of Proposed Rulemaking in this docket by Commission staff and Alaskan Northwest also compared the operating risks of this project with lower-48 pipelines. Based on a review of this Report and the comments, the Commission does not believe that operation risks, on balance, are significantly higher or lower than those of the typical pipeline in the lower-48 states. Consequently, the Commission proposes an Operation Phase Rate for the Alaska segment that is within the range of rates allowed by the Commission for most lower-48 pipelines. The proposed rate is 13 percent.[26] The Commission invites comments on the Alaska Delegate's report and on the specific questions of whether the Operation Phase Rate for the Alaska segment should be higher or lower than the rates allowed for other pipelines as well as the Operation Phase Rate proposed here.

The Delegate's Report suggests that because the Northern Border segment is so closely skin to lower-48 construction and operation, as compared to the Alaskan segment, the risk during operation for the Northern Border segment should be less than that for the Alaska segment, thereby justifying a lower Operation Phase Rate for the Northern Border segment. The tariffs proposed by the project sponsors for both segments of the pipeline would penalize investors for service interruptions by lowering the allowed rate of return during the interruption. Since the risk of service interruption is lower for the more conventional Northern Border pipeline design and route, the Operation Phase Rate should be lower than that allowed for the Alaskan segment. Consequently, the Commission proposes an Operation Phase Rate for the Northern Border system of 12 percent, one percentage point less than for the Alaska segment. This rate would apply to all facilities for the Northern Border system, including facilities built to carry Alberta gas in advance of Alaska gas. The Commission invites comments and evidence concerning the operation phase risks and the proposed Operation Phase Rate for the Northern Border segment.

b. Non-Incentive Rate. The IROR mechanism instituted by the Commission defines the Non-Incentive Rate as the value of the Operation Phase Rate plus an amount equal to the Project Risk Premium. The Project Risk Premium is intended to compensate equity investors for the financial risks incurred during the development, design, and construction of the project. Northwest Alaskan Pipeline Company has

[25] Notice of Delegate Report and Order Directing Tariff Filing, Docket No. RM78-12 (Feb. 22, 1979).

[26] The Hass Report suggests that the Operation Phase Rate should currently be 14.4 percent. Professor Hass also suggests that the rate be tied to the riskless government bond rate through a formula that adds 540 "base points" to the bond rate or 5.4 percentage points and the rate should fluctuate as interest rates change. With respect to the difference between the Alaskan and Northern Border segments, Professor Hass suggests a 2 percentage point differential, i.e., that Northern Border should be 2 points lower than Alaska, or 12.4%.

[27] "Determining Project Risk Premium," note 24 *supra*. For a similar approach to an analysis of the Project Risk Premium, see Hass Report, note 24 *supra*. Comments as to both of these approaches are invited.

prepared and made available to the Commission a study on the Project Risk Premium.[27] The Commission finds a great deal of merit in the methodology and approach in that report and will utilize many of its concepts in setting the Non-Incentive Rate.

In the notice of proposed rulemaking on September 15, 1978, the Commission used an illustrative example of a Project Risk Premium equal to two percentage points for the Alaska segment. Since then, both the project sponsor and the Alaska delegate's staff have done additional studies on the risk during the construction of the project and the appropriate compensation for those risks. The basic approach reflected in these studies is to attempt to determine what compensation should be provided to investors after the successful completion of the project to compensate them for the risk that the project would not be completed and all or part of their investment would be lost.[28]

The minimum compensation is that which would make an investment in the Alaska gas project a reasonable risk; that is, the probability of successful project completion multiplied by the reward for completion should equal the probability of non-completion multiplied by the lost investment. However, the two papers, that by the sponsor and that by Professor Hass, differ substantially in the probabilities of various outcomes and in the rate of return that should be granted if there were no risk of non-completion.

The essential risk faced by the project sponsors during the construction of the project is that the project will never be completed and placed into service. Both papers agree that the risk of project abandonment diminishes as the project moves closer to completion. In fact, one of the greatest risks of non-completion occurs prior to the receipt of all the necessary government approvals to commence construction and firm financial commitments. But once financing has been obtained and the necessary government approvals have been granted, the risk of failure to complete the project decreases greatly.

The Commission believes that there are four important issues to be determined prior to setting the Non-Incentive Rate and invites comments on these issues. The first is whether or not the Commission should compensate investors for the risks borne during the competitive proceedings before the Federal Power Commission and prior to the receipt of the conditional certificate in December 1977.

The second issue is whether compensation should be permitted for the risk of preparing and perfecting applications before this Commission. The risk includes both the possibility that the President and the Congress would have chosen one of the other two competing applications, and the possibility that the project would be abandoned prior to the granting of a final certificate. In a normal or conventional pipeline application, the project development costs and the probability of abandonment of the project are smaller than for the Alaska Gas Project, and competing applications are rare. Is it reasonable then to compensate investors for the risk that the project would not be developed beyond the President's *Decision* or the receipt of a certificate from the Commission if the project is in fact completed?

Third issue is the magnitude of the investor's potential loss in the event of non-completion. Since the sponsors are formed into a partnership, any profits and losses accrue to the sponsoring parent corporations. Investors may be able to write off tax purposes approximately half of any loss. Furthermore, depending upon the circumstances that cause the abandonment of the project, the Commission, in its discretion, could permit the equity investors to recover a

[27] A similar methodology was suggested by the Commission's Office of Regulatory Analysis in its comments on the notice of September 15, 1978. "Comments of the Office of Regulatory Analysis, Federal Energy Regulatory Commission, on Revised Notice of Proposed Rulemaking," Docket No. RM78-12, at 10-11 (Oct. 13, 1978).

portion of their investment in charges to current gas customers. The issue then is whether the Commission, in calculating the Project Risk Premium proposed in this notice, should give any weight to the possibility of recovering some of the investment in the project through charges to conumers in the event of non-completion. This issue also extends to whether applicants could have reasonably anticipated recovering some of the expenses accrued in the certification process if the project they proposed were not selected by the President.

The fourth issue concerns the rate of return on equity to be allowed if there is no risk of non-completion. In other words, if prior to the commencement of operations the project was certain to be completed, what would be the appropriate return to allow investors? [38] For the Project Risk Premium proposed in this notice, the Commission's analysis assumes a rate of approximately 9.5 percent would be appropirate for the project if there was a certainty of completion and uses this rate as the starting point for calculating the Project Risk Premium.

Appendix A to this notice sets forth the calculations to derive a value for the Project Risk Premium. The methodology generally follows the one advocated by the project sponsors in their paper, with the exception that a rate of return of 9.5 percent instead of the 15 percent advanced by the project sponsors is used as the starting point. In addition, this methodology would compensate the investors for the 67 percent chance (1 successful applicant among 3) that the conditional certificate resulting from the President's *Decision* would have been granted to one of the other two competing applicants before the FPC and the risk that their investment prior to the *Decision* would have been lost. Compensation for this risk was not proposed in the project sponsors' report on the Project Risk Premium.

Appendix A uses the probabilities advocated by the project sponsors for the risk of non-completion both prior to receipt of a final certificate from this Commision and prior to commencement of service.[39] Since the essence of setting the Project Risk Premium is to compensate equity investors for their perceived risks, it seems appropriate to use the investors' estimate of the probabilities of project abandonment. However, the Commission does have some reservations about the estimates submitted by Alaskan Northwest of the probability of project abandonment and construction schedules as perceived by the investors, and requests comments on the reasonableness of these assumptions. The methodology proposed by the sponsors also takes into account that, in the event of non-completion, the possibility that the investors will be able to recover approximately one-half of their investment in the project through a write off against income taxes. Based upon Cases No. 3 and 5 in Appendix A, the Commission proposes for purposes of comment a Project Risk Premium of 4 percentage points for the Alaska segment.

The probability of non-completion for the Northern Border segment seems to be less than that for the Alaska segment because of the possibility of the pre-delivery of Alberta gas. Because of the lower risk of abandonment of the Northern Border segment, the Premium proposed for purposes of comment for this segment is 3 percentage points.

Thus, the Non-Incentive Rate proposed for the Alaskan segment is 17 percent (the 13 percent Operations Phase Rate plus 4 percent). The Non-Incentive Rate proposed for the Northern Border segment is 15 percent

[38] The paper prepared by Professor Hass for the Alaskan Delegate assumes that a riskless rate would be appropirate if there were zero risk of non-completion and uses a rate of interest of approximately 8 percent. Hass Report, *supra*, note 24, at 28, 62.

[39] Northwest Alaskan, "Determining Project Risk Premium", note 24, *supra*, at 39.

(the 12 percent Operation Phase Rate plus 3 percent).[31]

c. IROR Risk Premium. In Order No. 17, the Commission defined the IROR Risk Premium as that increase in rate of return necessary to compensate equity investors for the risks created by the IROR mechanism. This Premium, when added to the Non-Incentive Rate, yields the Center Rate of Return.

Following the basic approach to risk compensation proposed by Northwest Alaskan in its paper on the Project Risk Premium, the IROR Risk Premium must be at least adequate to produce a reasonably attractive opportunity for equity investors. In other words, the mean or expected profits or revenues resulting from the imposition of the IROR mechanism should be at least as great as the revenues that would result in the absence of the IROR mechanism. (The mean or expected revenues is the sum of the product of each level of revenue times the probability of that revenue occurring.) A risk-neutral investor would then be indifferent to the imposition of the IROR mechanism.

In choosing an illustrative example of a 2 percent IROR Risk Premium in its September 15 notice, the Commission did not consider the possibility that a zero IROR Risk Premium would produce a reasonable opportunity for investors. This results from the definition of the Center-Point Cost Performance Ratio. The Center Point is defined to be the mean or expected Cost Performance Ratio.[32]

Expected (Mean) Return to Equity Investors

Probability	Cost Performance Ratio	Incentive Rate	Present Value Equity Return**
		(%)	($)
.08	8.0	22.6	41.75
.22	1.0	19.7	36.43
.25	1.2	17.8	31.32
.12	1.3	17.0	28.26
.10	1.4	16.4	25.89
.09	1.6	15.3	20.00
.06	1.8	14.5	14.67
.05	2.0	13.9	6.52
.03	2.2	13.3	3.59

Expected Cost Performance Ratio = 1.30.
Expected Incentive Rate = 17.6.
Expected Present Value Equity Return = $28.28.
*Center Rate = 17.0%, Center Point = 1.30, Maginal Rate = 8.0%.
**Present Value at 13.0% discount rate of return of equity and return on equity at the IROR and 4% annual depreciation.

Simple calculations will produce the result that the expected Incentive Rate of Return is slightly greater than the Center Rate and that the expected present value of the return to equity almost exactly equals the return at the Center Rate of Return (17 percent). In other words, no IROR Risk Premium is needed to produce a reasonably attractive investment opportunity.

Even though a zero IROR Risk Premium will produce such a chance and thus satisfy a risk-neutral investor, an argument can be made that a positive IROR Risk Premium is necessary because most investors are not risk neutral. An investor that is not risk neutral is more concerned about the "downside" potential of his investment (the bad results) than he is attracted to the upside potential (money gain) (the good results). Simply a fair chance is not

[31] In analyzing the methodology for setting the Project Risk Premium, it has become apparent that the Non-Incentive Rate should not be used as the rate for calculating the allowance for equity funds used during construction to be included in the rate base of the project. Instead the Commission now proposes to use the Operation Phase Rate as the AFUDC rate. This decision does not by itself reduce the attractiveness of the equity investment. This is discussed more fully in Appendix A.

[32] *See* Section II(B)(2) *infra*. To illustrate this result, the following table presents an example. In this table the IROR schedule of rates of return is based on a Non-Incentive Rate of 17 percent, a Marginal Rate of 8 percent, a Center Point of 1.3, and a zero IROR Risk Premium. This produces a Center Rate to be earned at the Center Point of 17 percent. A probability distribution on the values of the Cost Performance Ratio is assumed which produces a mean or expected Cost Performance Ratio of 1.3, thus satisfying the definition of the Center Point. The present value of the future returns to an equity investment of $100 is calculated based on a 13 percent discount rate (equal to the Operation Phase Rate). The return includes both the return of equity resulting from the depreciation of the pipeline over a 25 year period on a straight line basis and a return on equity at the rate indicated by the IROR schedule.

adequate to compensate him for the general uncertainty in rates of return created by the IROR mechanism. Thus, a small IROR Risk Premium is necessary to compensate the risk averse investor as opposed to the risk-neutral investor. It is proposed that for the Alaskan segment the IROR Risk Premium should be 0.5 percent and for the Northern Border the IROR Risk Premium should be 0.25 percent. These figures, when added to the Non-Incentive Rate of Return, yield Center Rates of Return of 17.5 percent and 15.25 percent respectively for the Alaskan and Northern Border segments.

2. Center Point. The Center Point is the value for the Cost Performance Ratio that is the expected value.[33] In other words, the Center Point should measure the level of cost overruns above the projected cost that is expected or likely to occur. In statistical terms, the Center Point is that level of costs obtained by adding together each possible level of costs multiplied by the probability of that level of costs occurring. The President's *Decision* (p. 157) expected costs overruns from the March 1977 estimates submitted by the project sponsors to be approximately 30% for Alaska (a Cost Performance Ratio of 1.3) and approximately 10% for Northern Border (a Cost Performance Ratio of 1.1).

The Commission's proposal for the Center Point is to base the Center Point on the relationship between the March 1977 cost estimates and the Certification Cost Estimate. Specifically, the Center Point for the Alaska segment shall equal the ratio of the March 1977, estimate (calculated using the same prices as the Certification Estimate) to the Certification Estimate multiplied by 1.3. (The *Decision* estimated a 30 percent cost overpaid for the Alaskan segment. *Decision* at 157.) In other words, if the Certification Cost Estimate exceeds the March 1977, estimate by 10 percent then the Center Point shall be set equal to 1.18 (1.18=1.3/1.1).

The March 1977, estimate will be recalculated using the same prices for labor and materials as used in the Certification Cost Estimate.[34] Such a recalculation is also anticipated to be required in order to allow the Commission to compare the March 1977, estimate with the Certification Estimate in order to determine that the Certification Estimate does not "materially and unreasonably" exceed the March 1977, estimate.

For the Northern Border segment, the Center Point shall equal the ratio of the March 1977, estimate to the Certification Estimate multiplied by 1.1. (The *Decision* estimated a 10 percent cost overrun for Northern Border. *Decision* at 157). Again, the March 1977, estimate shall be recalculated based on the prices used in the Certification Estimate for Northern Border. As an example, suppose that the certification Estimate exceeds the March 1977, estimate by 6 percent. In this case the Center Point would be set equal to 1.04 (1.04=1.1/1.06).

At the time the Certification Estimate is submitted to the Commission, project sponsors may petition the Commission to alter the values determined according to the above procedure. The basis for such a petition should be that the expected or mean level of costs exceed the Certification Cost Estimate times the Center Point as determined by the above procedure.

An alternative would be to postpone setting any value for the Center Point until after Certification Cost Estimates are submitted to the Commission. This would allow a more complete and thorough review of the potential for overruns from this estimate. However, in view of the project sponsors' request for expedition in resolving uncertainties surrounding the IROR mechanism,[35] the

[33] For a detailed discussion of the Cost Performance Ratio, see Section II(C), *infra*.

[34] Both estimates shall also contain AFUDC calculated from the Real Rate of Return. *See* Section II(C)(2).

[35] Alaskan Northwest, Petition for Expedited Rulemaking and Issuance of Final Order Establishing Rate of Return Range, Docket No. RM78-12 (Feb. 15, 1979).

Commission proposes to establish the above procedure or formula for the Center Point as part of this rulemaking.

As emphasized in Order No. 17, the March 1977 Cost Estimates will not be used as the basis for the Cost Performance Ratio. However, pursuant to the President's *Decision*, the Commission must determine that the Certification Cost Estimates do not "materially and unreasonably exceed" the March 1977 estimate (*Decision* at 36).

A Cost Performance Ratio of 1.0 would occur if the Actual Capital Cost of the project equals the Certification Cost Estimate. With a value of the Center Point equal to 1.3, the sponsors would earn the Center Rate of Return for the Alaska segment if actual costs exceed the Certification Cost Estimate by 30 percent.

3. Marginal Rate. The value of the Marginal Rate plays an essential role in determining the incentives to reduce cost created by the IROR mechanism. The Marginal Rate is the rate allowed for cost increases. Consequently, the Marginal Rate must be set at a value low enough to discourage cost overruns by making them unattractive.

In the comments submitted on the earlier notices of proposed rulemaking concerning the IROR mechanism,[36] a number of alternative approaches were proposed for setting the Marginal Rate. The Marginal Rate should be set at a level to discourage or make unattractive investments in cost overruns for the Alaska Gas Project. The various parties who submitted comments disagreed on what the level should be.

One view, expressed by Alaskan Northwest in their comments to the earlier notices, is that the Marginal Rate need only be slightly less than the rates of return available on other equity investments in the U.S. economy.[37] Using a rate of return of 13 percent after taxes as a measure of the rates of return that can be earned in other equity investments, this would mean that the Marginal Rate has to be only slightly less than 13 percent to make investing in overruns unprofitable.

However, a Marginal Rate only slightly less than alternative equity rates does not really create a significant incentive because the return is likely to exceed the cost of capital and therefore be profitable. It seems reasonable that the Marginal Rate must be substantially less than equity rates earned in other investments to create a true incentive. How much less is a matter of judgment.

An alternative approach is to argue that an incentive will be created only if the Marginal Rate is set at a rate less than what it will cost investors to raise the funds necessary to make an equity investment in overruns. This was the approach used as an example in the September 15, 1978, Revised Notice of Proposed Rulemaking (at 45). In that notice it was argued that equity investors would raise the funds necessary to finance their equity investment in an overrun by borrowing approximately 60 percent of the cost and selling equity common stock in their parent corporations to raise the other 40 percent. As that notice indicated, this would also result in a marginal rate of approximately 8 percent.

A third point of view is that, depending upon the circumstances in which the overrun occurs, an investment in an overrun in this project may be relative riskless. This would be true if the overrun occurred near the end of construction, and the project would be economically viable and successful even with the overrun. In that case, the Marginal Rate should be less than the rate obtainable on other riskless or relatively riskless investments (e.g., long-term corporate or government bonds). The rate of return on long-term corporate or government bonds has recently been in the range of 8 to 10 percent. On balance, and after reviewing these various arguments, the Commission proposes that the Marginal

[36] *See* notes 10 and 11, *supra*.

[37] "Comments of Alaskan Northwest Natural Gas Transportation Company, a Partnership," Docket No. RM78-12, October 12, 1978, pp. 16-19.

Rate should be 8 percent for both the Alaska and Northern Border segments.

Alaskan Northwest has filed a petition with the Commission requesting that the Commission establish a "zone of reasonableness" an upper and lower boundary to the IROR schedule.[38] For the lower boundary, this may result in a Marginal Rate equal to that boundary or floor. A high level for the floor would then diminish the incentives to reduce cost overruns created by the IROR mechanism. On the other hand, a floor and a ceiling would reduce uncertainty and risk to equity investors and may assist financing. A ceiling would also have the beneficial impact of placing an upper bound on the rate of return on equity that consumers could be required to pay. The issue of the "zone of reasonableness" shall be consolidated with the other IROR issues and rates of return discussed in this notice and will be resolved pursuant to this rulemaking.

The Commission solicits comments on the petition by the sponsors (a copy is attached to this notice) and invites suggestions for values of the floor and ceiling.[39] The Commission particularly requests comments on (1) the relationship between the floor and other IROR parameters (e.g., a floor requiring a reduced Marginal Rate to maintain the incentive to control costs), (2) the impact of a floor on equity and debt financing, (3) the requirement in the President's *Decision* that the IROR mechanism provide "substantial incentives" to reduce construction costs (*Decision* at 37), and (4) the impact on the IROR Risk Premium.

C. Cost Performance Ratio

The Cost Performance Ratio is the measure of cost overrun or underrun as compared to Projected Capital Costs (costs initially projected by the sponsors). Three important aspects of the Cost Performance Ratio are: the cost estimates used to establish the Projected Capital Costs figure; the previously discussed Center Point; and the calculation of the allowance for funds used during construction (AFUDC). In addition, the Cost Performance Ratio is influenced by considerations of which costs the sponsors will be held accountable. The succeeding sections of this notice, in discussing the Change-in-Scope Mechanism and Inflation Adjustment, address these latter two considerations.

1. Cost Estimates. Order No. 17 specified that the Projected Capital Costs for the project (the denominator of the Cost Performance Ratio) will be based upon the Certification Cost and Schedule Estimates submitted to the Commission prior to the final certification of the project. The President's *Decision* states that the Commission may decide not to issue a certificate if this cost estimate "materially and unreasonably exceeds" cost estimates submitted by the project sponsors in March 1977. (*Decision* at 36).

The Commission intends that the Certification Cost and Schedule Estimate (submitted prior to the issuance of a final certificate of public convenience and necessity) shall be the basis for the Projected Capital Costs in the Cost Performance Ratio. However, because of the extensive project development that must go forward even after the Certification Cost and Schedule Estimate has been submitted and approved by the Commission, and because of the unconventional nature of the pipeline design and routing, the Commission proposes to allow the cost estimate to be revised as later design changes occur. The President's *Decision* (p. 29) requires that the project sponsors submit a final design to the Federal Inspector prior to the initiation of actual construction. At the time of the submission of the final design to the Federal Inspector, the Commission proposes to allow the project sponsors to submit a revised certification cost

[38] Alaskan Northwest Natural Gas Co., "Petition for Expedited Rulemaking and Issuance of Final Order Establishing Rate of Return Range", Docket No. RM78-12 (Feb. 15, 1979).

[39] In requesting comment on this issue the Commission expresses no opinion as to the sufficiency of the legal arguments advanced by petitioner.

estimate incorporating changes in cost resulting from design changes. With the advice of the Federal Inspector, the Commission will again make a determination whether the Certification Cost Estimate as adjusted for changes in pipeline design does "materially and unreasonably exceed" the March, 1977, estimate. The Commission invites comments on this procedure.

Changes in design may cause a change in the quantity or type of labor and materials or a change in construction techniques and schedule. The resulting changes in costs if approved by the Commission, will be incorporated in the Certification Cost Estimate. However, the prices used in the preparation of the Certification Cost Estimate approved by the Commission shall not be altered as a result of design changes. All adjustments for price changes shall be through the Inflation Adjustment Mechanism described below. However, if the design changes result in significant changes in the importance of a cost category then the weights used to construct the cost index may be changed.

2. Real Rate of Return. In Order No. 17, the Commission defined a Real Rate of Return as the rate used to calculate the AFUDC or interest during construction included in the Projected Capital Costs and the Actual Capital Costs for the project. It must be emphasized that this rate of return will not be used to calculate the AFUDC to be included in the rate base for determining cost of service. The only use of the Real Rate of Return is for the purpose of determining the Cost Performance Ratio in the IROR mechanism.

The Real Rate of Return used as an illustrative example in Order No. 17 was 5 percent. This value still seems reasonable and is the value proposed by the Commission in this notice for both segments of the project. The Commission solicits comments and alternative values for this return.

3. Relation to the Center Point. The Center Point Ratio is the ration which is the expected or mean value of the Cost Performance Ratio. In other words, it is a measure of the expected or mean value for cost overruns for the project.[40] It is the Commission's intention to specify a formula or procedure to determine the Center Point for the Alaska segment and the Northern Border segment as part of this rulemaking. The value of of the Center Point is dependent upon the Change-in-Scope Mechanism adopted by the Commission. The Center Point should be a measure of the mean or expected level of costs for which the project sponsors are to be held responsible and would not include changes in costs that are covered by the Change-in-Scope Mechanism. Consequently, a very liberal Change-in-Scope Mechanism that classified a large portion of cost increases into the non-penalty category would mean that the Commission would choose a lesser Center Point than would otherwise be the case. Conversely, if very few or no changes in scope are allowed and consequently the project sponsors are held accountable in the IROR mechanism for almost all cost increase, the Center Point should be greater. The paper prepared by the Institute for Defense Analysis analyzes the relationship between Change-in-Scope and Center Point.[41]

III. Change-in-Scope

In this rulemaking, the Commission intends to specify the Change-in-Scope Procedure which is an essential part of the Incentive Rate of Return mechanism. This notice will discuss alternative Change-in-Scope Procedures and will propose a specific procedure. Interested

[40] The concept of mean or expected value used here is the definition from statistical theory, which is the weighted average of all possible outcomes where each possible Cost Performance Ratio is weighted by the probability of that ratio occurring. If the probability distribution of costs for the project is skewed to the right than the mean or expected value of the Cost Performance Ratio will be to the right of both the modal value (the value that has the highest single probability of occurring) or the median value (the value for which there is a 50 percent chance of exceeding).

[41] McCullough Report, note 24 *supra*.

parties are invited to comment on the proposed Change-in-Scope Procedure and to suggestion alternatives or improvements.[42]

The basic intent of the Incentive Rate of Return mechanism is to lower the allowed rate of return for equity investors as costs for the project rise relative to the projected cost or to increase rates of return as costs are reduced. This mechanism is to provide an incentive for project managers to keep costs as low as possible. However, it is the intent of the Commission not to penalize project sponsors for some cost increases. The mechanism for specifying cost increases that will not result in a penalty on the rate of return is the Change-in-Scope Procedure.

A. Goals

In developing a Change-in-Scope Procedure for the IROR mechanism, the Commission hopes to achieve four goals. The first is to maintain and not dilute the incentive to reduce costs created by the IROR mechanism.

In the comments on the earlier notices of proposed rulemaking concerning the IROR mechanism, the project sponsors stressed the importance of distinguishing between costs under the control of the sponsors and costs beyond their control in determining which cost increases would result in a penalty in rate of return.[43] In practice it is unlikely that any cost increase will be either totally under the control of the project sponsors or totally beyond their control. In fact, all cost increases will be controllable by the project sponsors in varying degrees. In many cases the specific event that causes the cost increase may be beyond the control of the sponsors, yet the sponsors would have a major influence over the size of the cost increase. Good project management could keep the cost impact of an unanticipated event very low while inefficient management could allow major cost increases to occur. Consequently, any attempt to place all unanticipated cost increases into an uncontrollable category will inevitably mean that many cost increases over which the project sponsors do have some control will be classified as uncontrollable. This would dilute or weaken the incentives to control or manage costs.

The second goal is to reduce the administrative burden of implementing the Incentive Rate of Return mechanism for this Commission, the Federal Inspector, and the project sponsors. An elaborate and complicated Change-in-Scope Mechanism could result in major administrative burdens for all parties concerned.

The third goal is to develop clear and unambiguous rules for the Change-in-Scope Procedure in order to reduce future controversy or disagreement. Major controversies and legal conflicts have developed in contracting procedures used by the Defense Department or between private firms over who is responsible for cost overruns. A major goal of the Commission is to minimize the potential for such disagreement and conflict.

One of the difficulties in creating an incentive mechanism is that incentives may be created that were not anticipated and are undesirable or perverse. The fourth goal is to prevent this possibility. The Defense Department experience with incentive contracting provides examples of where incentives for contractors turned out to be quite different from those anticipated by the developers of the incentive contract mechanism.

B. Proposed Procedure

In order to achieve the four goals described above, the Commission proposes a Change-in-Scope Mechanism that will place most of the responsibility for cost increases on the project sponsors.[44] Only cost increases resulting

[42] *See, e.g.*, Northwest Alaskan, "Allowable Cost Estimate Revisions", note 24, *supra*.

[43] *See, e.g.*, "Comments of Alaskan Northwest Natural Gas Transportation Company, a Partnership," June 23, 1978, Docket No. RM 78-12, at 10-14.

[44] It should be noted that the center rate has been set in recognition of the degree of responsibility for cost increases which the proposed Change-in-Scope mechanism will impose upon the project sponsors. A lesser degree of responsibility would argue for a lower center rate.

from four events will be classified as nonpenalty cost increases. If one of these four events occurs, the Projected Capital Cost of the project will be altered prior to determining the Cost Performance Ratio. The events are (1) wars, (2) any disaster declared by the President of the United States pursuant to the Disaster Relief Act of 1974, Pub. L. 93–288, 88 Stat. 143, (3) major design changes compelled by changes in Federal or State laws or regulations applicable to natural gas pipelines enacted or adopted subsequent to the Federal Inspector's approval of the final design of the pipeline, and (4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the Alaska Natural Gas Transportation System from that approved by the Federal inspector in the final design of the pipeline.

Further, the Commission believes that the project sponsors or investors in any one segment, Alaskan or Northern Border (*see* text accompanying note 2, *supra*), of the pipeline should not be responsible for cost increases resulting from construction delays in the other segments, or from a delay in the initiation of gas production at Prudhoe Bay. This will be accomplished by defining the Actual Capital Cost for a segment as those costs incurred up to the point that segment is capable of rendering service even though other segments are not yet capable of rendering service or gas is not capable of delivery from Prudhoe Bay. In other words, AFUDC will cease to be added to the Actual Capital Costs for a segment when that segment is complete and ready to begin transporting gas even if, for whatever reason, it is not actually transporting gas.[45]

This Change-in-Scope Mechanism should achieve the four above-described goals. The mechanism provides for maximum incentives to reduce costs since almost all cost increases would be the responsibility of the project sponsors. The proposed procedure will not impose a major administrative burden on either the Government or the project sponsors since the changes in scope for which the Projected Capital Cost for the project may be altered are likely to be few in number. It is unlikely that there will be substantial disagreement or controversy over the procedure during the course of construction. The final design submitted to the Federal Inspector pursuant to the President's *Decision* will be of such detail that any Government-ordered changes that altered the pipeline route or pipeline capacity should be capable of identification. Finally, because the changes in scope are few in number, there is little opportunity for manipulation of the Change-in-Scope Mechanism.

C. The Project Sponsors' Alternative

In its paper on the subject, Northwest Alaskan proposes an elaborate and complex procedure for altering the Projected Capital Costs of the project for broad categories of events.[46] The drawback of this proposed procedure is that it would fail to satisfy any of the four goals described above.

Under the sponsors' proposed procedure, so many cost increases could be classified as a change in scope, the incentives to reduce costs would be diluted. In addition, the administrative burden involved in administrating this complex procedure seems large. The rules for deciding when a change in scope has occurred, and for determining the resulting increase in projected costs, are not clear or precise in the sponsors' proposal and could result in a great deal of controversy and disagreement.

[45] This applies only to the computation of the Cost Performance Ratio and not to amounts capitalized for rate purposes. Also, it is not intended to indicate when charges to shippers are to be levied. Actual Capital Costs is a concept developed solely for the IROR mechanism and differs in a number of important ways from the conventional concept of rate base used to determine transportation rates for pipelines. It must be emphasized that any rules or procedures for determining Actual Capital Costs do not effect other Commission procedures which have been or will be established for calculating rate base and transportation rates for the Alaska gas project or any other project.

[46] Alaskan Northwest, "Allowable Cost Estimate Revisons", note 24, *supra*.

Finally, because of the complexity of this procedure, perverse incentives may be created. The paper prepared for the Alaskan Delegate by the Institute for Defense Analysis (IDA) attempts to further refine some of the concepts introduced by Northwest Alaskan by using probability distributions on uncertain events and parameters affecting costs.[47] However, the proposals of IDA do not seem to be any more practical or desirable than the proposals by Alaskan Northwest.

D. Relation to Other Parameters

As described earlier, the Change-in-Scope Mechanism must be compatible with other parameters of the Incentive Rate of Return mechanism, in particular, the Center Point and IROR Risk Premium. Since the Commission's proposed Change-in-Scope Mechanism would not allow the projected cost of the project to be increased except in a few situations, the Center Point should measure the expected cost of the project including an allowance for cost overruns that could result from unanticipated events. If a very liberal Change-in-Scope Mechanism were adopted by the Commission, where many cost increases would be classified as resulting from a change in scope, and thus the projected cost of the project would be increased, then the Center Point should be reduced to 1.0 or less.

Similarly, a very liberal Change-in-Scope Mechanism would greatly reduce the uncertainty in rates of return that is created by the IROR mechanism and thus would be an argument for reducing the IROR Risk Premium and the Center Rate. Also, the Commission's proposal to allow the projected cost of the project to be altered between the time the Certification Cost Estimate is approved by the Commission and the submission of the final pipeline design to the Federal Inspector greatly reduces the potential for unanticipated increases in construction costs due to changes in pipeline design.

E. Conflict Resolution

Even though the number of events for which the projected costs of the project will be altered are limited in number and are not likely to occur with great frequency, it is still important that the Commission establish a procedure to determine if a change in scope has occurred and the size of the resulting change in Projected Capital Costs. When the change in scope has occurred, the project sponsors shall submit to the Federal Inspector both an explanation of the change in scope and an estimate of the increase in Projected Capital Costs for the project. The decision of the Federal Inspector will be final.[48]

In order to minimize any uncertainty about this procedure, the Commission intends for the Federal Inspector to act on each change in scope case as expeditiously as possible after the alleged change in scope has occurred Comments on this procedure are invited.

IV. Inflation Adjustment

In Order No. 17, the Commission determined that it would not be reasonable to penalize project sponsors for cost increases that were the result of general inflation in the U.S. economy. Consequently, the Commission intends to adjust Actual Capital Costs for the project by a measure of the rate of inflation so that both the Deflated Actual Capital Costs and the Projected Capital Costs are calculated in the same base-year prices; those being either 1978 or 1979. The Alaskan Delegate,[49] and the project sponsors[50] have prepared papers on the inflation adjustment mechanism and the Commisson invites comments

[47] McCullough Report, note 24, *supra*.

[48] This procedure is premised upon Congressional action adopting the President's Limited Reorganization Plan establishing the Office of the Federal Inspector, as discussed in the President's *Decision*. In the event that this plan is not adopted, or adopted in a form which precludes the above-described procedure, the Commission will propose an amendment to the procedure.

[49] Northwest Alaskan, "Recommended Inflation Adjustment", note 24 *supra*.

[50] Alaska Gas Project Office Report, note 24 *supra*.

on their approach to inflation adjustment.

The inflation adjustment procedure also plays a role in determining the risks to be borne by the equity investors resulting from the Incentive Rate of Return mechanism. An inflation adjustment mechanism that closely tracks actual prices paid by project sponsors will provide greater protection (and thus reduce risks for unanticipated inflation) than will an index that is more broadly based and may not accurately track pipeline construction costs for this project. Thus, the choice of inflation adjustment procedure plays a role in determining the size of the IROR Risk Premium and thus the Center Rate.

There are a number of alternative methods for adjusting actual costs for inflation. This notice will propose a specific procedure for the inflation adjustment and invites comments, criticisms and suggestions for alternatives as part of this rulemaking.

A. Proposed Procedure

The Cost Performance Ratio is the ratio of Deflated Actual Capital Cost to Projected Capital Cost. Actual Capital Costs must be deflated to the same base year for cost estimation as was used in the preparation of the Projected Capital Costs. The Commission intends to develop an inflation index that will measure the increases in construction cost for the project resulting from general inflation in the U.S. economy. This index will be used to deflate the Actual Capital Costs to base-year prices. In reviewing the proposals by the project sponsors and the Alaska Delegate for an inflation adjustment mechanism, the Commission proposes a procedure similar to that advocated by the project sponsors but with some important exceptions. In choosing an inflation adjustment mechanisms, the Commission has the same principles or goals in mind as for the Change-in-Scope Mechanism.[31]

The proposed inflation adjustment procedure has four primary features:

(1) The index used will be a "composite" or "hybrid" index calculated as a weighted average of existing published indices. The Commission does not propose to use actual prices paid by the project sponsors for goods or services as a measure of inflation for any cost category.

(2) Approximately 40 categories of costs will be used and an index chosen that measures the inflation in costs for that category.[32] The index chosen will be representative of overall inflationary experience in the U.S. economy for that cost category and will not be oriented toward and conditions attached to this notice specify the cost categories and the index to be used for each. (Terms and Conditions, Nos. 5 and 8.)

(3) The weights used to calculate the average of the 40 indices will be based on the projected costs of the project sponsors. At the time the project sponsors submit their Certification Cost Estimate, they will be required to divide their projected costs into each of the 40 cost categories for each year or quarter. Each cost category's proportion of total costs in that year or quarter will then be used to weight that cost category. The project sponsors may, at their convenience, choose to utilize either annual or quarterly weights.

(4) For any construction that occurs beyond the projected construction schedule for the project, the weights specified for the last year of the projected construction period will be the weights used.

Since the project sponsors have no way of influencing or controlling how the inflation adjustment mechanism will work during the construction period, maximum incentive will be given to the project sponsors to procure materials and hire labor at the lowest possible wages and prices.

The Inflation Adjustment Procedure, including the establishment of the weights for the index and the choice of indices to be used, will have been developed prior to the beginning of

[31] *See* Section III(A), *supra*.
[32] *See* Condition 18, *infra* (Schedule).

construction. Therefore, the administration of the procedure during the construction period should be simple and uncomplicated and not place a large administrative burden on either the Commission or the project sponsors. The danger of a more complex and elaborate inflation mechanism is that it creates undesirable and perverse incentives that no one can now anticipate and thus defeat the purpose of the Incentive Rate of Return mechanism.

B. Use of Actual Prices

The project sponsors have argued that for certain categories of costs, especially major items such as labor or steel, no existing index accurately measures inflation in these prices. Therefore the project sponsors may experience price increases greater or less than that measured by any existing index; thus the sponsors propose to use actual prices paid as an "index".[53]

The Commission does not favor the use of actual prices paid as a measure of inflation, especially for such major categories of project cost as labor and steel. Such an approach would eliminate any incentive created by the IROR mechanism to reduce prices paid for these goods and services. Eliminating the incentive to reduce these prices created by the IROR mechansim would not meet the requirement in the President's *Decision* to develop an IROR mechanism that provides substantial incentives to reduce costs (*Decision* at 37).

The Commission understands that because of the huge size of the project and its location in Alaska it is quite possible for the project sponsors to experience unique or special circumstances in negotiating labor wage rates and prices for steel pipe. Consequently, the project sponsors may pay prices for labor and steel that are different from the prices paid in other construction projects in other parts of the country. In submitting their Certification Cost Estimates for the project, the project sponsors should take these special circumstances into account in estimating the prices to be paid.

For example, since Alaskan wages are substantially higher than in other parts of the country, the Commission anticipates that the wage rates for labor used in the Certification Cost and Schedule Estimate will reflect the premium that one must pay for labor in the high-cost area of Alaska. This would seem to provide adequate protection to the project sponsors for the unique circumstances for construction in Alaska. Thereafter, a more broadly-based national index of increases in wage rates will be used as a measure of inflation both for increases in Alaskan wages as well as in the lower-48 states. Similarly, in the estimate of prices paid for steel included in the Certification Cost Estimate, the project sponsors should include their best estimate of the price that they will have to pay for steel pipe including any special premiums or discounts resulting from the large size or other special features of the order.

C. Alternative Weighting Schemes

There are a number of other possible methods for calculating the weights to be used in the hybrid cost index. However, they all appear less desirable than the method proposed above. For example, instead of having weights that changed from year to year or from quarter to quarter, it is possible to use constant weights over the entire construction period. However, this would not accurately reflect any difference in timing expenditures for each category of cost. If in any one year or quarter the project sponsors spend a large amount for a particular category of costs, then that category should receive a larger weight in the cost index for that year or quarter.

A second alternative is to base the weights on actual costs incurred rather than on projected costs. For example, the weight given to steel could be based

[53] Alaskan Northwest, "Recommended Inflation Adjustment," *supra* note 24 at 7.

on the actual proportion of total costs accounted for by steel rather than on the initial estimate by the sponsors. This might be an acceptable approach. However, it may impose a major administrative burden on the project sponsors. To divide actual costs into 40 categories could require a heavy investment of time and money by project sponsors and their subcontractors. It may also impose a major burden on the Commission staff and the Federal Inspector to review the resulting detailed breakdown of actual costs incurred.

The third alternative, which was suggested by the project sponsors, is to allow the sponsors to submit new estimates of weights prior to each quarter.[54] The major concern of the Commission is that the quarterly review of submitted weights would impose a major administrative burden on the Commission or the Federal Inspector to determine reasonableness. Moreover, the alternative has the potential for involving the project in considerable controversy during the construction period if disagreement should occur about the size of these weights.

A simple alternative would be to use a single existing index from the many published by Government and private firms to deflate total costs. An example would be the Gross National Product (GNP) deflator for non-residential construction. However, since this is an index that is appropriate for the average or typical mix of goods and services used in non-residential construction, it may not accurately represent the mix of goods and services used in pipeline construction. Consequently, this imposes the risk on the project sponsors that their actual inflation rates could be substantially higher or lower than that measured by the GNP deflator. The use of a single index does not bias the inflation adjustment mechanism against or in favor of the sponsors; it does, however, create more uncertainty in the application of the IROR.

V. Tariff Issues

On March 12, 1979, the project sponsors for the Alaska and Northern Border segments of the ANGTS filed their proposed tariffs with the Commission pusuant to the Commission's order and notice of February 22, 1979.[55] Interested parties are hereby notified that these tariffs have been filed with the Commission. Comments, protests, and interventions concerning the tariffs should be submitted to the Commission as part of the comments and reply comments submitted pursuant to this notice of proposed rulemaking. The intent of the Commission is to resolve tariff issues as well as to decide the rates of return and other features of the Incentive Rate of Return mechanism as part of a single rulemaking procedure.

The report of the Alaska Delegate on the tariff and Operation Phase Rate issues identifies four major tariff issues that affect the risk borne by the project sponsors as being controversial.[56] In their filed tariffs, the project sponsors have proposed resolutions for these issues in the form of specific tariff provisions.

Interested parties are invited to submit comments on whether the tariffs proposed by the project sponsors should be adopted, satisfy the requirements of the President's *Decision*, are supported by the evidence presented before the Commission in Docket Nos. CP75–96, *et al.* (*El Paso Alaska, et al.*) and meet the requirements of the Natural Gas Act. In this matter, the sponsors are specifically directed to submit as a part of their comments the reasons that the tariffs, as filed, conform to the *Decision* and are supported by the evidence in Docket Nos. CP75–96, *et al.* The future Commission order issued after the rulemaking procedure initiated by this notice will either approve the filed

[54] 54 *Id.*

[55] "Notice of Delegate Report and Order Directing Tariff Filing" Docket No. RM78–12 (Feb. 22, 1979).

[56] These were the billing commencement date, interim rate phasing, penalty for service interruption, and billing procedure. Delegates Memorandum, note 3 *supra.*

tariffs of the project sponsors or will require modifications based upon the comments received pursuant to this notice. If for some tariff issues the comments received do not provide an adequate factual record on which the Commission can make a decision, then the Commission may specify further administrative procedures.

The Commission will reserve one tariff issue for resolution in the proceeding dealing with the applications to "pre-build" a portion of the Alaska gas pipeline to transport Canadian gas in advance of Alaskan gas (Docket Nos. CP78–123, *et al*). This issue is the depreciation rate to be used in calculating the cost of service for Canadian gas transported through the Northern Border Pipeline. The relationship between the depreciation rate and the financing of the "pre-built" facilities and the Alaska segment requires that this issue be considered in Docket Nos. CP78–123, *et al*. In particular, the Commission believes that the relationship between the depreciation rate and the future delivery of Alaska gas can not adequately be resolved in this rulemaking.

This rulemaking will only consider the filed tariffs of the companies owning and operating the Alaska and Northern Border segments of the Alaska gas transportation system. Tariffs of companies that have purchased Prudhoe Bay gas and intend to transport this gas through the Alaska gas system ("shippers") will be considered at a later date after gas purchase contracts have been negotiated and tariffs have been submitted to the Commission for approval.

The tariff for Northern Border primarily covers the transportation of Alberta gas as part of an "advance delivery" or "pre-delivery" project. Amendments to that tariff may be necessary before the transportation of Alaskan or other gas can take place.

VI. Summary of Commission's Proposal

Order No. 17 left three major IROR issues or parameters to be resolved in a future proceeding. These are (1) the Change in Scope procedure, (2) the inflation adjustment procedure, and (3) the IROR schedule.

Once the Federal Inspector gives the go-ahead to begin construction after the final design has been approved, the Projected Capital Costs for the project (the denominator of the Cost Performance Ratio) will only be altered in the event of (1) wars, (2) any disaster declared by the President of the United States pursuant to the Disaster Relief Act of 1974, Pub. L. 93–288, 88 Stat. 143, (3) major design changes compelled by changes in Federal or State law or regulations applicable to natural gas pipelines enacted or adopted subsequent to the Federal Inspector's approval of the final design of the pipeline, and (4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the Alaska Natural Gas Transportation System from that approved by the Federal Inspector in the final design of the pipeline. Upon application by the project sponsors, the Federal Inspector will determine whether a change in scope has occurred, and if so, the resulting change in the Projected Capital Costs.

Prior to the approval of the final design by the Federal Inspector, the Commission will allow the Certification Cost Estimate to be revised to account for any major changes from the design assumed in the preparation of the Certification Cost Estimate.

The adjustment of the Actual Capital Costs of the project to account for general inflation in the economy will be done through a single composite cost index. This cost index will be the weighted average of some 40 indices published by the Federal Government or respected private firms. Each index will measure the inflationary experience in one cost category. The weights will be derived from the importance of that cost category in the projected cost of the project.

The following three tables specify the values for the parameters that determine

the IROR schedule and provide the IROR schedule itself for the Alaska and Northern Border segments. For the Alaska segment, the proposed IROR scheduled would allow a 23 percent rate of return if the actual costs of the project adjusted for inflation are the same as projected in the Certification Cost Estimate. At a 30 percent overrun (a Cost Performance Ratio of 1.3), the return drops to 17.5 percent (the Center Rate). At an overrun of approximately 150 percent (a Cost Performance Ratio of 2.47), the allowed rate would drop to 13 percent.

For the Northern Border segment, the proposed IROR schedule would allow a 16 percent return if actual costs of the segment adjusted for inflation are the same as projected in the Certificate Cost Estimate. At a 10 percent overrun, the rate would drop to 15.25 percent (the Center Rate). At a 60 percent overrun (a Cost Performance Ratio of 1.6), the allowed rate would drop to 13 percent.

Table 1.—*Proposed IROR Parameters*

	Alaska segment	Northern border
Center Point*	1.3	1.1
Operation Phase Rate (%)	13.0	12.0
Non-Incentive Rate (%)	17.0	15.0
Center Rate (%)	17.5	15.25
Marginal Rage (%)	8.0	8.0
Real Rate (%)	5.0	5.0

*Assumes that the Certification Cost Extimate plus AFUDC equals the March 1977 estimate plus AFUDC reclaculated in the same base year prices used to calculate the Certification Estimate.

Table 2.—*Proposed IROR Formulas*

R = Incentive Rate of Return.
A = Cost Performance Ratio.

Alaska Segment

Northern Border
$R = [(17.5)(1.3) + 8(A - 1.3)]/A$
$= 8 + 12.35/A.$

Northern Border

$R = [(15.25)(1.1) + 8(A - 1.1)]/A$
$+ 8 + 7.95/A$

Table 3.—*Proposed IROR Schedule*

Cost performance ratio	IROR	
	Alaska	Northern border
0.8	23.44	17.97
1.0	20.35	15.98
1.1	19.23	15.25
1.2	18.29	14.65
1.3	17.50	14.13
1.4	15.82	13.70
1.6	15.72	12.98
1.8	14.96	12.43
2.0	14.18	11.99
2.2	13.61	11.63
2.4	13.15	11.32

VII. Written Comment Procedures

The Commission invites interested persons including Staff to submit written data, views, and other information concerning the matters set forth in this notice. An original and 14 copies should be filed by May 4, 1979. All comments should be verified and submitted to the Federal Energy Regulatory Commission, Office of the Secretary, 825 North Capitol Street, NE., Washington D.C. 20426 and should reference Docket No. RM78-12. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NE., Washington, D.C. during regular business hours.

Because of the complexity and importance of the issues presented in this notice, the Commission intends that those participating in this proceeding should serve their comments on other participants, and have an opportunity to respond to the initial comments made in response to this notice. In order for this to take place, any person intending to participate in this proceeding shall notify the Secretary of the Commission in writing on or before April 16, 1979. A service list will then be prepared and

mailed to those who have stated an intention to participate. The initial comments shall be filed with the Office of the Secretary as stated above. In addition, each party shall serve their initial comments by May 4, 1979 to those on the service list. Reply comments are to be verified and filed with the Office of the Secretary in accordance with the above procedures by May 16, 1979, and shall be served upon parties listed on the service list by the same date.

Those persons wishing to make oral presentation of data, views and arguments on particular matters may petition the Commission for oral argument. Such petition should carefully describe the issue(s) and the reasons for having them argued.

In providing proper service of the initial comments and any reply comments, attention is directed to the regulations of the Commission found at 18 C.F.R. 1.17(b) [1977] which permits service by mail. In addition, those who provide comments and reply comments are directed to the subscription and verification provisions found at 18 C.F.R. 1.16 [1977].

In order that all interested parties may be apprised of this matter, the Commission orders that the Secretary, in addition to publishing this notice in the **Federal Register**, shall serve copies of the same to all parties of record in Docket Nos. CP78–123, CP78–124, CP78–125, RM78–12, and related dockets, said service to be accomplished pursuant to 18 C.F.R. 1.17 [1977].

(Natural Gas Act, as amended, 15 U.S.C. §§ 717, *et seq.*; Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350 (1978); Department of Energy Organization Act, Pub L. No. 95–91; Executive Order No. 12009, 42 FR 46267; DOE Delegation Order No. 0204–8, 42 FR 61491; Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. §§ 719, *et seq.*; President's *Decision and Report to Congress on the Alaska Natural Gas Transportation System*, approved by joint resolution, Pub. L. No. 95–158, 91 Stat. 1268 (1977); Administrative procedure Act, 5 U.S.C. § 553.)

In consideration of the foregoing, and subject to further modification following comment and hearing respecting the proposed Terms and Conditions, the following list of conditions will be appended to the conditional certificates of public convenience and necessity issued by the Commission on December 16, 1977, in Docket No. CP78–123, *et al.*

By the Commission.

Lois D. Cashell,
Acting Secretary.

Note.—There were fifteen (15) Terms and Conditions arising from Order No. 17 on the certificates of public convenience and necessity for the ANGTS. This notice of proposed rulemaking provides for modification of certain existing Terms and Conditions, the addition of certain further Terms and Conditions and the renumbering of Terms and Conditions. For clarity, the following list contains previously ordered terms and conditions as well as those arising from the instant notice of proposed rulemaking. The Commission solicits comments on all the enumerated terms and conditions (to the extent those terms and conditions have not been resolved in prior orders) and welcomes comments on their interrelationship.

Terms and Conditions

1. Applicability

The Incentive Rate of Return (IROR) will apply to two of the three segments of the Alaskan Natural Gas Transportation System within the United States, as defined in the President's *Decision and Report to Congress on the Alaska Natural Gas Transportation System* (referred to hereinafter as the Decision). These segments are: (1) the portion of the system within the State of Alaska, and (2) the portion of the system from the United States/Canadian border near Monchy in the Province of Saskachewan to a point near Dwight in the State of Illinois. In the following terms and conditions, the term "pipeline" refers to each of these two segments, and the terms and conditios apply to each.

2. Cost Performance Ratio

The second finance term and condition of the *Decision* (at page 36) provides that the rate of return on equity during the operating period of the pipeline will be increased if the pipeline is completed under projected cost and reduced if the pipeline is completed over projected cost. The relationship between projected cost and completed cost will be determined by a Cost Performance Ratio. The Cost Performance Ratio is the ratio of the Deflated Actual Capital Costs (See Condition 3, below) to the Projected Capital Costs (See Condition 4, below), using the same base year.

3. Deflated Actual Capital Costs

The Deflated Actual Capital Costs will be determined at the start of operations as the sum of direct construction costs actually incurred in the construction of the pipeline after conversion into base year prices (see Condition 5 below) plus an allowance for funds used during construction (AFUDC) calculated from the Real Rate of Return (see Condition 6 below). AFUDC will be calculated quarterly, based on the Deflated Actual Capital Cost incurred prior to the beginning of the quarter. When a segment (see Condition 1, above) is complete and able to commence operations, accrual of AFUDC will cease for that segment.

4. Projected Capital Costs

The Projected Capital Costs will be determined at the start of operations as the sum of direct construction costs included in the Certification Cost and Schedule Estimate approved by the Commission pursuant to Condition 7, below, and after any adjustments for changes in scope (see Condition 10, below) or resulting from design changes prior to the Final Design (see Condition 9, below) plus AFUDC calculated from the Real Rate of Return (see Condition 6, below). AFUDC will be calculated quarterly, based on the Projected Capital Costs estimated to be incurred prior to the beginning of the quarter.

5. Inflation Adjustment

The direct construction costs actually incurred, excluding interest during construction, will be deflated to base year prices, where the base year will be that used in calculating the Projected Capital Costs. The inflation index will be a composite index calculated as a weighted average of existing published indices or price data. The attached schedule (see Condition 18, below) contains the forty (40) categories of cost to be used and the index or prices to be used for each category. When the project sponsors submit their Certification Cost Estimate, all projected costs will be divided into each of the cost categories for each year or quarter. The proportion of total costs in that year or quarter for each cost category will be used as the weight for that cost category. For any construction that occurs beyond the projected construction schedule for the project, the weights specified for the last year of the projected construction period will be the weights used.

6. Real Rate of Return

The Real Rate of Return to be used to calculate the AFUDC or interest during construction included in the Projected Capital Costs and the Deflated Actual Capital Costs shall be five percent (5%). The Real Rate of Return shall only be used in determining the Cost Performance Ratio in the IROR mechanism and will not be used to calculate the AFUDC included in the rate base for cost of service.

7. Certification Cost and Schedule Estimate

Pursuant to the second finance condition in the *Decision*, the applicant for a certificate of public convenience and necessity for the pipeline shall submit to the Commission a Certification Cost and Schedule Estimate, adjusted to reflect any design changes resulting from the Agreement on Principles with Canada and any addendum thereto, for comparison with the capital cost estimates filed by Alcan

with the Federal Power Commission on March 8, 1977. This estimate will include costs actually incurred prior to submission of the estimate. This Certification Cost and Schedule Estimate will be submitted in 1978 or 1979 base-year prices and with costs set forth according to formats to be specified by the Commission (see Condition 8, below). The March 1977, cost estimate referred to in the second finance term and condition in the Decision must also be resubmitted in the same format, and recalculated in the same base-year prices for comparability with the certification estimate. An explanation of any significant differences between the March 1977, and the Certification Cost and Schedule Estimate must be provided. The date of the base-year period for submitting costs may be determined by the applicant. With these estimates, the applicant shall also provide a Construction Plan and Pipeline Design which show the techniques and procedures the applicant proposes to use in constructing the pipeline and provide a detailed description of the pipeline as it will appear when completed.

8. Cost Estimate Format

All cost estimates shall be submitted to the Commission according to a Cost Estimate Format to be determined by the Commission. Prior to submittal of the Certification Cost and Schedule Estimate, the applicant may submit a proposal for the Cost Estimate Format to the Commission. The Cost Estimate Format will specify the functional categories or components into which the total cost estimate must be divided according to the time period in which the costs are estimated to occur. The breakdown of costs shall be in sufficient detail that the Commission may compare the various cost estimates and determine the reasonableness of any changes.

9. Final Design

After the submission to and acceptance of Final Design by the Federal Inspector as required by the *Decision*, the Certification Cost and Schedule Estimate will be altered to reflect changes in quantities or types of materials, labor, services and project development or construction schedule and construction techniques resulting from changes in design or schedule between the time the Certification Cost Estimate was prepared and the approval of the Final Design. Prices of labor, materials, or services used in the Certification Estimate will not be altered unless as a direct result of a design change in the Final Design.

The project sponsors shall submit the revised Certification Estimate, including both an explanation of the alleged design or schedule change and an estimate of the change in costs or schedule, to the Federal Inspector. The Inspector shall review it, and forward it to the Commission for final determination. In the event that the project sponsors and the Federal Inspector cannot reach agreement about the change in cost or schedule, the project sponsors (and other interested parties) may submit legal briefs, documentation, or other written evidence to the Commission prior to the Commission's determination.

10. Change in Scope

The Projected Capital Costs shall be increased in an amount equal to the amount of cost increases attributable to change in scope events beyond the control of the project sponsors. Such change in scope events shall be limited to (1) wars, (2) any disaster declared by the President of the United States pursuant to the Disaster Relief Act of 1974, Pub. L. 93–288, 88 Stat. 143, (3) major design changes compelled by changes in Federal or State laws or regulations applicable to natural gas pipelines enacted or adopted subsequent to the Federal Inspector's approval of the final design of the pipeline, and (4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the Alaska Natural Gas Transportation System from that approved by the

Federal Inspector in the final design of the pipeline. Cost increases attributable to change in scope events shall be calculated based upon the assumptions and parameters used to calculate the Certification Cost Estimate to the maximum extent practicable.

11. Change in Scope Procedure

Whenever the project sponsors believe a change in scope event (as defined above) has occurred, the project sponsors shall submit to the Federal Inspector an explanation of the alleged change in scope and an estimate of the increase in Projected Capital Costs for the project. The Federal Inspector will approve or disapprove the inclusion of such increases in Projected Capital Costs, pursuant to procedures to be determined by the Inspector in the regulations he will promulgate, and his decision will be final.

12. Center Point

The Center Point is the mean or expected value of the Cost Performance Ratio. Based upon the findings of the President's *Decision*, the Center Point (CP) for the Alaska segment shall be calculated from the following formula:

CP equals 1.3 times March, 1977, cost estimate in base-year prices plus AFUDC divided by Certification Cost Estimate Plus AFUDC.

The Center Point for the Northern Border segment shall be calculated from the following formula:

CP equals 1.1 times March, 1977, cost estimate in base-year prices plus AFUDC divided by Certification Cost Estimate Plus AFUDC.

The base-year prices shall be those utilized in the preparation of the Certification Cost Estimate. For purposes of this condition, the March, 1977, estimate and the Certification Cost Estimate shall include AFUDC calculated from the Real Rate of Interest (see Condition 6, above).

13. Operation Phase Rate

The Operation Phase Rate is the rate of return on equity that will be allowed after the pipeline is in operation and after the one-time adjustment to the rate base has been made. The Operation Phase Rate shall be 13 percent (13%) for the Alaska segment and 12 percent (12%) for the Northern Border segment. The Operation Phase Rate shall be the rate used to calculate the allowance for equity funds used during construction to be included in the rate base of the project.

14. IROR Formula

The Incentive Rate of Return shall be set equal to $[(17.5)(CP)+8(A-CP)]/A$ for the Alaska segment and $[(15.25)(CP)+8(A-CP)]/A$ for the Northern Border segment where A is the Cost Performance Ratio (see Condition 2, above) and CP is the Center Point (see Condition 12, above).

15. Financing Plan

The financing plan (Exhibit L) submitted pursuant to the Commission's regulations (18 CFR 157.14) as part of the application for a certificate of public convenience and necessity under Section 7 of the National Gas Act shall describe how the applicant proposes to finance the estimated cost of the project and any overruns, including the proportions of debt and equity financing to be used. If the actual financing of the project deviates significantly from the financing plan submitted to, and approved by, the Commission, these terms and conditions and any determinations concerning parameters of the IROR schedule may be altered by the Commission.

16. Cost of Service Calculation

The allowed rate of return on equity used to calculate cost of service during operation of the pipeline will be the Operation Phase Rate defined above in Condition 13. The rate base will include an allowance for equity funds used during construction. The equity rate of return during construction used to calculate the allowance is the Operation Phase Rate defined above the Condition 13. The allowance will also include a

one-time adjustment calculated pursuant to Condition 17, below. The cost of service for the pipeline shall include a charge for depreciation of the one-time adjustment, and a charge for an equity rate of return on the one-time adjustment where the rate of return is the Operation Phase Rate. The one-time adjustment will be depreciated in the same manner as the remainder of the allowance for equity funds used during construction.

17. Adjustment to Rate Base

Upon completion of construction and commencement of the initial operation of the pipeline, a one-time adjustment to the equity AFUDC account in the rate base will be calculated in three steps. First, for each year in the assumed 25-year operating life of the pipeline, a revenue stream for equity will be derived assuming that the equity investment including AFUDC in the pipeline at the start of operation is fully recovered by depreciation over a 25-year period in equal annual installments, and that an annual return on equity is derived by applying the Incentive Rate to the undepreciated equity investment at the beginning of each year. Second, the present worth of this revenue stream will be calculated using a discount rate equal to the Operation Phase Rate determined pursuant to Condition 12, above. Third, the difference between this present worth sum and the equity investment including equity AFUDC at the start of operations will be added to the equity AFUDC in the rate base of the project. If the difference is negative, the allowance for equity funds during construction in the rate base will be reduced by the difference.

Within six months after the initial operation of the pipeline, the one-time adjustment must be submitted for approval by the Commission. If the Commission reduces the one-time adjustment, the excess in transportation charges incurred during the intervening period will be subtracted from the one-time adjustment. Similarly, any shortfall will be added to the one-time adjustment.

18. *Categories of Costs for Inflation Adjustment.*

Cost Categories to be used as weights in hybrid index and suggested proxy prices or indices

Cost Category	Suggested Price Index Proxy	Source
1. Labor	1.Labor	
1.a. Welders and Helpers	1.a. Journeymen Structural and Reinforcing	Engineering News Record
1.b. Operators and Oilers	1.b. Boilermakers (AK Operating Engineering)	Engineering News Record
1.c. Drillers and Powder Men	1.c. Skilled Labor (AK Pipeliners)	Engineering News Record
1.d. Pipe fitter	1.d. Carpenters	Engineering News Record
1.e. Carpenters	1.e. Electricians	Engineering News Record
1.f. Electricians	1.f. Teamsters	Engineering News Record
1.g. Truck Drivers	1.g. Skilled Labor	Engineering News Record
1.h. Blasters and Powder Men	1.h. Skilled Labor	Engineering News Record
1.i. Operators diesel labor	1.i. Skilled Labor	Engineering News Record
1.j. Other unskilled labor	1.j. Unskilled Labor	Engineering News Record
2. Material Earthmoving	2. Bituminous Coal—Location Survey for Similarly Skilled Personnel Categories	Bureau of Labor Statistics American Management Asso.
3. Line Pipe	3. API Line Pipe F.O.B. Mid-Continent, Pennsylvania	U.S. Department of Labor
4. Gas Turbine Compressor Sets and Auxiliary equipment	4. Gas Compressor (centrifugal Unmotored)	PPI 11410401
5. Gas Transmission Systems and Auxiliary Equipment	5. Pumps, Compressors and Equipment	
6. Generation systems	6. Generators and Generator Sets	PPI 117902
7. Communication and Metering Connection Wire and Other Electrical Equipment.	7. Electrical Machinery	PPI 117
8. Valves, Flanges and Fittings	8. Valves and Fittings	PPI 114501
9. Pipe Insulation and Coating	9. Nonmetallic Mineral Products	PPI All Construction Material Index
10. Building and Utilities including Building Systems (e.g. HVAC, Lighting)	10. Special Commodity Grouping	PPI 1222013
11. Cement Hot Line and Mixed Products	11. Portland Cement	PPI Fabricated Metal Products
12. Other Nonmetallic Mineral Materials	12. PPI Special Commodity Grouping	PPI, All Construction Material Index
13. Air Passenger	13. Special Commodity Grouping	GAB
14. Air Cargo	14. Published Tariff for Average Price Per Passenger Mile	GAB
15. Water	15. Published Tariff for Average Price Per Ton Mile for Air Cargo	GAB
16. Rail	16. Published Tariff for Avg. Cost per Ton Mile	GCC
17. Rail	17. Published Tariff for Avg. Cost Per Ton Mile in Rail Cargo	GCC
18. Truck	18. Published Tariff for Avg. Cost Per Ton Mile for Truck	GCC
19. Facilities	19.a. Department of Commerce Composite Index	Table S-11 of Survey of Current Business
19.a. Government Owned	19.b. Special Commodity Grouping—Food	PPI
19.b. Food Supplies	19.c. CPI—All Items—U.S.	Bureau of Labor Statistics
20. Other Type Trailers	20. Tractors, other than Farm, Crawler Type, Diesel 160 Hwl Engine HP and Over	PPI 1118927
21. Other Heavy Construction Equip.	21. Construction Machinery and Equipment	PPI 112
22. Transportation Equipment	22. Transportation Equipment	PPI 14
23. Miscellaneous Construction Machinery and Equipment	23. Construction Machinery and Equipment	PI 112
24. Diesel Fuel	24. Diesel to Commercial Customers Profile	PPI 0573000106
25. Other POL	25. Petroleum Products Refined	PPI 057
26. Other Miscellaneous Commodities (e.g. welding rods, etc.)	26. Industrial Commodities Grouping	PPI
27. Rents, Municipal and Hobbs and Private Land.	27. Do Not Include in Price Index	Bureau of Labor Statistics
28. Purchased Field Data	28. Index of Homeownership Costs Lower Costs of Rental Housing	Bureau of Labor Statistics
	29. CPI—All Items U.S.	

NOTE.—PPI: Producers Price Index—Source Bureau of Labor Statistics Publication Monthly Engineering News Record Simple 20 City Average—Publication Currently Dodge Manual 20 City Average—Available Annually CPI—Consumer Price Index Publication Monthly U.S. Global Line (Not published as a list price publication on request actual selling price may be different. American Management Association Executive Compensation Survey is available once a year. Linear interpolation suggested for quarterly estimates.

Appendix A

Project Risk Premium

The sponsor of the Alaska segment of the Alaska gas transportation system (Northwest Alaskan) has proposed a methodology to calculate the Project Risk Premium. The Project Risk Premium is to compensate the equity investor for the risk of non-completion. Pursuant to the President's *Decision* (p. 37), this risk is to be borne by equity investors; and consumers shall not be asked to pay any charge related to Alaska gas prior to the "completion and commissioning of operation". As far as it goes, this methodology is valid. However, it is limited in that it can not consider any uncertainty other than the risk of project abandonment in each year. For example, this methodology does not incorporate any uncertainty about the construction schedule or costs. Instead, the paper considers two cases, a schedule of six years and a longer schedule of seven years.

Though the methodology is correct, the sponsors have erred in the choice of values for three parameters. First, the sponsors use a relatively high rate of 15 percent as the AFUDC rate for equity in calculating the risk adjusted rate base. The correct value should be a low risk rate, for example, the rate currently earned on Government bonds. The adjustment to the rate base compensates for risk to investors, and the AFUDC rate should not further compensate for risk. This is not to imply that the actual equity AFUDC component of the rate base of the project should be calculated from the low risk rate. In calculating the theoretical construct of a risk adjusted rate base, however, the low risk rate should be used. In the calculations of a Project Risk Premium that follow a rate of 9.5 percent is used.

The second error is in failing to consider expenditures prior to 1978. The Project Risk Premium should be adequate to compensate equity investors for risks incurred from the date their decision was made to first apply for a certificate from the Commission including the risk that the Commission would grant a certificate to some other applicant. Consequently, expenditures during the competitive hearings before the Federal Power Comission and the probability of failure should be included. In some of the revised cases presented below, two percent of the total equity investment is assumed to be invested prior to the granting of a conditional certificate in late 1977. Further, it is assumed that the probability of failure to receive this conditional certificate was 0.67. In other words, the Alcan project had only a one-third chance of being selected by the President and the Congress from the three competing applications.

A third error is in the justification for a parameter value rather than the actual value used. The sponsor's paper assumes that in the event of noncompletion or project abandonment the Commission will allow one-half of the direct equity investment to be recovered by charges to existing gas customers using some unstated tariff mechanism. A better interpretation is that the equity investment can be considered a loss for tax purposes and written off against the other income of the partners. This would result in a Federal and State tax savings of approximately one-half of the equity investment.

Further one can reasonably question some of the values assumed both for the construction schedule and the probabilities of abandonment. The project sponsors assume that a final certificate will not be issued until sometime in 1981 in Profile No. 1 and not until 1982 in Profile No. 2. Additional justification for such a lengthy certification process should be supplied before such a schedule can be assumed to be reasonable.

The project sponsors have in effect assumed in Profile No. 1 that there is a 56 percent chance of abandoning the project prior to the issuance of a final certificate and a 60 percent chance prior to completion. In Profile No. 2, this increases to 65 percent prior to final

certification (1982) and 68 percent prior to completion (1985). In other words, there is only a 32 to 40 percent chance that this project will be built by the current project sponsors.

The following tables present seven examples of cases of a Project Risk Premium under various assumptions. In all seven cases, the following assumptions are made:

(1) The profiles of costs from 1978 through 1985 are the same as assumed by Northwest Alaskan.

(2) The equity rate used to calculate the risk adjusted rate base is 9.5 percent instead of 15 percent used by Northwest Alaskan.

(3) In the event of abandonment, 50 percent of the direct equity investment is assumed to be recovered as a reduction in Federal and State taxes on the other income of the partners.

(4) The Operation Phase Rate used to calculate the size of the Project Risk Premium is 13 percent instead of the 15 percent assumed by the Northwest Alaskan. The formula for determining the Project Risk Premium is then:

0.1839 Risk Adjusted Rate Base at 9.5% equity AFUDC divided by .1839 Normal Rate Base at 13% equity AFUDC.

The following is a discussion of the seven cases:

Case No. 1

In this case the assumptions made by Northwest Alaskan are used for the shorter 7 year construction period with the exception of the 9.5 percent rate used to calculate the risk adjusted rate base and the 13 percent Operation Phase Rate. Instead of the 5.4 percent Project Risk Premium calculated by Northwest Alaskan, this case produces a Premium of only 1.7 percent. In other words, a Non-Incentive Rate of 14.7 percent and an Operation Phase Rate of 13 percent (also used as the AFUDC rate for equity) would be adequate to compensate equity investors for their risks. The major reason why the risk premium is reduced from that calculated by Northwest Alaskan is that the 13 percent equity AFUDC rate already provides substantial compensation for the risks during construction relative to the riskless rate of 9.5 percent.

Case No. 2

This is the same as Case No. 1 except that the annual probabilities of abandonment are reduced to one half of those assumed in the Northwest Alaskan paper. This results in only a 35 percent chance of abandoning the project prior to completion instead of the 60 percent chance assumed by the sponsoring for the 7 year construction schedule. This reduces the Project Risk Premium to a *minus* 0.57 percent. In other words, the Non-Incentive Rate should be slightly less than the Operation Phase Rate. The 13 percent AFDUC rate more than compensates for the construction phase risks borne by investors.

Case No. 3

The Northwest Alaskan probabilities of abandonment are used for the shorter (7 year) schedule. However, 2 percent of the equity investment is now assumed to be spent prior to 1978, during the competitive hearings before the FPC. The risk of failure or abandonment is 0.67 during this period assuming that each of the three competitors have an equal chance of being selected. The Project Risk Premium in this case increases from the 1.7 percent derived in Case No. 1 to 3.1 percent. This increase is due to the inclusion of risk prior to 1978.

Case No. 4

With the exception of the 9.5 percent rate and the 13.5 percent Operation Phase Rate assumptions, this case is the same as the longer 8 year construction profile presented by Northwest Alaskan. The Project Risk Premium for this case is 3.3 percent instead of the 8.5 percent derived by Northwest Alaskan.

Case No. 5

This case is the same as No. 4 except that credit is given for the risks borne by

investors prior to 1978. This increases the Premium of 3.3 percent in Case No. 4 to 5.1 percent in this case.

Case No. 6

This case is the same as No. 5 except that the probabilities of abandonment have been reduced in half for the years after 1978. The 0.67 risk prior to 1978 is unchanged. This reduces the Premium of 5.1 percent in Case No. 5 to only 0.7 percent. Clearly, the probabilities of abandonment play the major role in determining the Project Risk Premium. With this assumption, the probability of abandoning the project between the years 1978 and 1985 is reduced from 68 percent (assumed by Northwest Alaskan) to only 41 percent.

Case No. 7

This case is the same as Case No. 2 except that credit is given for the risk borne by sponsors prior to the granting of a conditional certificate in 1977. The shorter schedule is used and the probabilities are only one-half those assumed by the sponsors. The Project Risk Premium in Case No. 2 of *minus* 0.57 is increased to *plus* 0.25 percent.

The methodology developed by Northwest Alaskan provides additional insight into the role that the AFUDC equity rate plays in compensating for the risk of noncompletion. An equity AFUDC rate above the low risk rate already provides some compensation for risk during construction, and thus reduces the size of the Project Risk Premium. For example, consider two variations in Case No. 5. In this case, the longer 8 year construction schedule is used, the probabilities of abandonment are those assumed by Northwest Alaskan, and a 67 percent chance of abandonment is assumed prior to 1978. The Project Risk Premium for this case is calculated to be 5.09 percent based on an AFUDC equity rate of 13 percent.

Case No. 5a

In this subcase, the AFUDC equity rate is assumed to be set at the rate of 9.5 percent instead of 13 percent. The AFUDC equity rate provides no compensation for risk, and thus the Project Risk Premium would be increased from 5.09 percent to 8.5 percent.

Case No. 5b

In this subcase, the AFUDC equity rate is assumed to be set at the high rate of 19.2 percent. This will produce an actual rate base equal to the risk adjusted rate base. Thus no Project Risk Premium is necessary to further compensate for the construction phase risks, and the Non-Incentive Rate should equal the Operation Phase Rate.

Consequently, the Commission's choice of an AFUDC rate is of little importance as long as the methodology described above for setting the Project Risk Premium is followed. A low equity AFUDC rate will result in a larger Project Risk Premium and thus a larger Non-Incentive Rate. For simplicity, it would be desirable to set the equity AFUDC rate equal to the Operation Phase Rate instead of the Non-Incentive Rate as specified in Order No. 17. The calculation of the Project Risk Premium is made much more complicated if the Non-Incentive Rate must also be used as the equity AFUDC rate, since one must know the equity AFUDC rate before calculating the Project Risk Premium.

Table A-1.—*Calculation of Project Risk Premium Under Alternative Assumptions*

	Pre-1978	1978	1979	1980	1981	1982	1983	1984	1985
CASE NO. 1									
Equity Investment (%)		8	9	11	13	20	20	20	
Year End Normal Rate Base (RB) (13% equity AFUDC rate)		9.04	19.25	34.19	53.32	82.85	116.23	153.94	
Probability of Abandonment		.125	.35	.125	.125	.05	.05	.01	
Year End Risk Adjusted Rate Base (RB_A) (9.5% equity AFUDC rate)		9.44	25.07	43.21	67.49	99.26	132.44	168.11	
Project Risk Premium based on 13% Operation Phase Rate (%):1.66.									
CASE NO. 2									
Equity Investment (%)		8	8	11	13	20	20	20	
Year End Normal Rate Base (RB) (13% equity AFUDC rate)		9.04	19.26	34.19	53.32	82.85	116.23	153.94	
Probability of Abandonment		.0625	.175	.0625	.0625	.0251	.01	.005	
Year End Risk Adjusted Rate Base (RB_A) (9.5% equity AFUDC rate)		9.08	20.97	36.44	56.41	85.05	115.79	149.18	
Project Risk Premium based on 13% Operation Phase Rate (%): −0.57.									
CASE NO. 3									
Equity Investment (%)	2	7	7	11	13	20	20	20	
Year End Normal Rate Base (RB) (13% equity AFUDC rate)	2.26	10.46	19.73	34.73	53.93	83.55	117.01	154.82	
Probability of Abandonment	0.67	.125	.35	.125	.125	.05	.02	.01	
Year End Risk Adjusted Rate Base (RB_A) (9.5% equity AFUDC rate)	4.57	13.84	30.79	50.37	76.45	109.59	143.68	180.67	
Project Risk Premium based on 13% Operation Phase Rate (%):3.09.									
CASE NO. 4									
Equity Investment (%)		8	8	8	10	12	18	18	18
Year End Normal Rate Base (RB) (13% equity AFUDC rate)		9.04	19.26	30.80	46.10	65.66	94.53	127.16	164.03
Probability of Abandonment		.125	.35	.20	.125	.125	.05	.02	.01
Year End Risk Adjusted Rate Base (RB_A) (9.5% equity AFUDC rate)		9.44	25.07	42.27	62.98	90.55	123.43	157.19	193.27
Projected Risk Premium based on 13% Operation Phase Rate (%) 3.28.									

Table A-1.—*Calculation of Project Risk Premium Under Alternative Assumptions*—Continued

	Pre-1978	1978	1979	1980	1981	1982	1983	1984	1985
CASE NO. 5									
Equity Investment (%)	2		7	8	10	12	16	18	18
Year End Normal Rate Base (RB) (13% equity AFUDC rate)	2.26	10.46	19.73	31.34	46.71	66.35	95.31	128.04	165.03
Probability of Abandonment	.67	.125	.35	.20	.125	.125	.05	.02	.01
Year End Risk Adjusted Rate Base (RB_A) (9.5% Equity AFUDC rate)	4.56	13.83	30.78	50.08	72.75	102.76	137.53	172.94	210.69
Project Risk Premimum based on 13% Operation Phase Rate (%): 5.09.									
CASE NO. 6									
Equity Investment (%)	2	7	7	8	10	12	16	16	16
Year End Normal Rate Base (RB) (13% equity AFUDC rate)	2.26	10.46	19.73	31.34	46.71	66.35	95.31	128.04	165.03
Probability of Abandonment	.67	.0625	.175	.10	.0625	.0625	.025	.01	.005
Year End Risk Adjustment Rate Base (RB_A) (9.5% equity AFUDC rate)	4.57	13.21	25.13	38.98	56.07	77.96	106.96	137.60	171.21
Project Risk Premium based on 13% Operation Phase Rate (%): 0.69.									
CASE NO. 7									
Equity Investment (%)	2	7	7	11	13	20	20	20	.....
Year End Normal Rate Base (RB) (13% equity AFUDC rate)	2.26	10.46	19.73	34.74	53.93	83.55	117.01	154.82	.....
Probability of Abandonment	.67	.0625	.175	.0625	.0625	.025	.01	.025	.....
Year End Risk Adjusted Rate Base (RB_A) (9.5% equity AFUDC rate)	4.57	13.21	25.13	41.30	62.09	91.42	122.64	156.94	.....
Project Risk Premium based on 13% Operation Phase Rate (%): 0.26.									

Appendix B

Petition of Alaskan Northwest Natural Gas Transportation Company

UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Incentive Rate of Return for the Alaska Natural Gas Transportation System

Petition for Expedited Rulemaking and Issuance of Final Order Establishing Rate of Return Range

This petition is filed by Alaskan Northwest Natural Gas Transportation Company, a Partnership, the person designated and selected by the President and Congress to construct and operate the Alaskan segment of the Alaska Natural Gas Transportation System. Petitioner invokes the provisions of the Alaska Natural Gas Transportation Act of 1976 (ANGTA), the Joint Resolution of November 2, 1977, signed into law November 8, 1977 (H.J. Res. 621, Pub. L. 95–108, 95th Cong., 1st Session), and 18 CFR 1.7.

Petitioner requests the immediate institution of a rulemaking proceeding and after notice, comment, and cross comment, the promulgation of a rule which will establish (a) that the incentive rate of return structure ultimately prescribed in this docket will not result in the Partnership earning a rate of return greater, or lesser, than that which is just and reasonable; and (b) the range of rates of return for this project which, in due consideration of the need to attract capital and the need to protect consumers, constitutes the "zone of reasonableness" for the rate of return for this project.

The Partnership requests expedited consideration by the Commission of this petition, and expedited resolution, by final order, of the issues presented herein. In support of this petition, the Partnership would respectfully show the following:

I.

The interest of the Partnership in the rule requested is manifest. The Partnership is the holder of the Commission's conditional certificate of convenience and public necessity issued December 16, 1977, conditionally authorizing the Partnership to construct and operate the Alaskan segment of the Alaska Natural Gas Transportation System. The Partnership is successor to the person designated and selected by the President in his September 22, 1977 *Decision and Report to Congress* as the person to construct and operate the Alaskan segment of ANGTS, such succession having been authorized and approved by the Commission in its order in this docket of June 30, 1978. The interest of the Partnership in the incentive rate of return proceeding has been expressly recognized by the Commission in Order No. 17 (December 1, 1978) and Order No. 17–A (January 17, 1979).

II.

The Commission has concerned itself in this docket, RM78–12, with implementation of the requirements of the President's *Decision and Report* concerning a variable rate of return mechanism for the Alaska Natural Gas Transportation System (ANGTS). By rulemaking issued May 8, 1978, the Commission has entertained multiple rounds of comment and cross comment and has, through Order Nos. 17 and 17–A, established the framework, but not the details, of the incentive rate of return mechanism.

Although not in agreement with the terms and conditions set forth in Order Nos. 17 and 17–A, the Partnership does not here seek to relitigate the terms and conditions imposed by the Commission but, rather, the Partnership seeks a supplemental proceeding, and supplemental rules, which the Partnership believes, and represents to the Commission, are essential to private financing and timely construction and operation of the Alaskan segment of ANGTS.

The rule requested herein involves but one of several matters which must be promptly and affirmatively resolved if the Alaskan segment of ANGTS is to proceed on a timely basis and if private sector financing is to be arranged.

The Partnership cannot characterize any one of the outstanding unresolved issues as more or less critical than the others. Project progress depends upon a multitude of government decisions not yet made as, for example, decisions on design parameters, processing costs, right-of-way stipulations, proximity questions, financial participation by the State of Alaska, producer contracts, and so forth.

Notwithstanding the fact that the proceeding and rule requested herein will not be the sole determinant of the project's scheduling and financing, the issues here presented are vital to scheduling and financing. With prompt and affirmative action by the Commission on this petition, coupled with prompt and affirmative action by other government authorities, and resolution of other outstanding issues, the project can proceed.

III.

This petition focuses upon the impact of incentive rate of return procedures established in Order Nos. 17 and 17–A. Without reiterating the interrelationship of other government decisions on project scheduling and finance, the Partnership seeks to underscore that the proceeding and rule requested herein, with issuance of a final rule no later than May 15, 1979, is of critical importance to a schedule designed to place ANGTS in service in 1984. A delay in the scheduled in-service date for the System will result in higher costs of construction and higher gas prices for U.S. consumers. A delay will jeopardize the ability of the Partnership to secure private financing for the project. Delay is, therefore, totally incompatible with the public interest.

IV.

The probability of substantial and irretrievable slippage in the Partnership's schedule for placing the Alaskan segment of ANGTS in service arises because of factors beyond the control of the Partnership. Arctic weather conditions are such that certain essential field programs can only be conducted during the late spring, summer and early fall months; if these field programs are not initiated and substantially completed during 1979, the Partnership loses the ability to move forward on necessary design, engineering and cost estimation work on a timely basis. These essential field programs are costly; if they are to be undertaken, the Partnership must underwrite this cost, through the payment or commitment of equity funds by the individual partners. If the partners cannot advance the necessary equity funds, it follows that the field programs cannot be undertaken, delay will ensue, and costs will rise.

The Partnership has been placed in a position where it cannot reasonably be expected to generate the equity funds necessary to perform all essential field work during 1979. An expenditure several times the $21,700,000 presently budgeted for the first six months of 1979 would be necessary to accomplish the field work and carry forward on a timely basis related planning, design, engineering and cost estimation work. The Partnership, and the individual partners, cannot invest risk capital of this magnitude or, indeed, at any level beyond the commitments presently outstanding, without reasonable assurance that such an investment is reasonable, prudent and consistent with the interests of their customers and shareholders. Such assurance is presently lacking.

V.

The issue which the Partnership is impelled to raise with the Commission is one of timing. It is the considered judgment of the Partnership that the issues which must be resolved in order to assess the impact of the Commission's incentive rate of return structure cannot be resolved within the framework of Order Nos. 17 and 17–A prior to May 15, 1979. If all outstanding issues cannot be resolved by that date, increased equity support to fund 1979 field programs is unlikely and, accordingly, the summer of 1979 will be lost and a 1984 start-up date will be in doubt.

The Partnership emphasizes May 15 as critical for the issuance of a final order herein, and resolution of other outstanding issues which are presently creating uncertainty and delay. An order issued by the Commission by that date, together with the successful resolution of other issues, will permit the Partnership an opportunity to reconsider the level of budget support for the balance of 1979. If the Partnership is in a position to conclude that increased equity investment for the balance of the year is reasonable and prudent, the necessary field work, or substantial portions of it, can still be undertaken during the balance of 1979.

VI.

In Order No. 17–A, the Commission concluded that an allowance for funds used during construction (AFUDC) should be included in the calculation of the cost performance ratio. This decision was based upon the Commission's finding that the Canadian IROR mechanism contained an allowance for AFUDC, and that "similar treatment for the sponsors of the U.S. segments requires the inclusion of AFUDC in the IROR cost performance ratio for the U.S. companies." (Order No. 17–A, page 4.)

The need perceived by the Commission for uniformity between Canadian and U.S. treatment of IROR issues will be met by the issuance of the rule requested herein. On January 24, 1979, the National Energy Board of Canada issued its incentive rate of return rules for the Canadian segments of ANGTS, and in these rules, the Canadian authorities have prescribed a minimum rate of return. The National Energy Board has noted:

"The need for, and magnitude of, a minimum rate of return must be related to the effect of major cost overruns on the cost of transmission, to the attracting of capital for

financing the pipeline and to the protection of financing of the Dempster link pursuant to the Canada-U.S. Agreement. . . ."

Inasmuch as the Commission has already decided that the Canadian and U.S. IROR approach must be consistent, so crucial an ingredient as the concept of a minimum rate of return (now expressly adopted and provided by the National Energy Board for the Canadian segments of ANGTS) should be brought forward into the Commission's rules relating to the incentive rate of return.

VII.

The Partnership requests that the Commission, by expedited rulemaking, give the minimum assurances necessary to equity sponsors that the incentive rate of return mechanism, as finally put in place some months hence, will not operate to deprive equity investors of a just and reasonable rate of return on their investment.

The Commission is requested to initiate a rulemaking proceeding, and issue a final rule by May 15, 1979, on the basis of written comments, cross comments and oral argument (if appropriate) which rule will establish:

A. That the incentive rate of return mechanism established in Order Nos. 17 and 17–A will not function to reduce the Partnership's rate of return below that level which is just and reasonable for this project; and

B. The upper and lower limits (the "zone of reasonableness") for the rate of return permissible for this project, giving due consideration to all factors involved in a rate of return determination under the standards of *FPC* v. *Hope Natural Gas*, 320 U.S. 591.

The Partnership anticipates that it can provide sworn comment support for a determination of the lowest rate of return which will attract capital to the project, the anticipated capital structure of the project, and the range and nature of project risks. Other interested parties, including Staff, can surely offer evidence on the highest rate of return that would be just and reasonable, giving due regard to the protection of gas consumers. If initial comments are filed by March 15 and cross comments by April 15, it is reasonable to believe that the Commission can issue a final order by May 15.

VIII.

The names, titles and mailing addresses of the persons to whom all correspondence and communications concerning this application should be addressed are as follows:

Darrell B. MacKay, Vice President, Northwest Alaskan Pipeline Company, 1801 K Street, N.W., Suite 901, Washington, D.C. 20006.
Jack D. Bachman, Esquire, General Counsel, Northwest Alaskan Pipeline Company, P.O. Box 1526, Salt Lake City, Utah 84110.
Rush Moody, Jr., Esquire, Vinson & Elkins, 1101 Connecticut Avenue, N.W., Suite 900, Washington, D.C. 20036

Wherefore, Alaskan Northwest Natural Gas Transportation Company prays for the expedited approval of its Petition, institution of appropriate proceedings, and issuance of an appropriate final order no later than May 15, 1979.

Respectfully submitted,

Rush Moody, Jr.,

Vinson & Elkins, 1101 Connecticut Avenue, N.W., Suite 900, Washington, D.C. 20036, (202) 862-8500. Attorneys for Alaskan Northwest Natural Gas Transportation Company, a partnership.

[Docket No. RM79-12]

¶ 32,018 Voluntary Annual Reporting of Electric Utility Conservation Activities

44 F. R. 22751 (April 17, 1979).

[18 CFR Part 2]

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission proposes to delete Section 2.14 of its General Rules which provides for the voluntary annual reporting of electric utility conservation activities. In view of the expanded scope of Federal and State programs to promote energy conservation, and specific directives to electric utilities relating to their participation in insulation and solar energy programs, the continued reporting of this generalized information may not now represent a cost-effective effort in the public interest.

DATE: Comments will be received in the Office of the Secretary through the close of business, Thursday, May 17, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (Reference Docket No. RM79–25)

FOR FURTHER INFORMATION CONTACT:

Bernard B. Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275–4770; or

Charles F. Reusch, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275–4216.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (the Commission)[1] hereby gives notice that it proposes to amend its General Rules by deleting § 2.14 which was originally established by Order No. 495 issued November 13, 1973, 50 FPC 1574, 38 FR 31963 in Docket No. R–454. Citing authority granted by Section 202(a) of the Federal Power Act, as amended, 49 Stat. 848, 16 U.S.C. 824a(a), the Commission at that time instituted a voluntary annual reporting procedure, covering conservation activities of electric utilities, to facilitate governmental and public awareness of such activities and to promote the conservation and effective use of natural resources used in electric power production. Utilities were then considered to be in a unique position to initiate effective programs for their respective customers on the prudent utilization of electric energy. Therefore, each utility was requested to provide annually on May 1, the following information: (1) Its overall policies for the conservation and efficient utilization of natural resources, (2) its program of research and development in conservation, and (3) its general plan on how to achieve continually increasing efficiencies in the generation, transmission, distribution and utilization of electric energy.

In view of the expanded scope of Federal and State programs to promote energy conservation, and specific directives to electric utilities relating to their participation in insulation and solar energy programs, the continued reporting of this generalized information may not now represent a cost-effective effort in the public interest. Also, the promotion of energy conservation and efficient use of energy resources is a primary function of the Secretary of Energy, rather than of this Commission. (National Energy Conservation Policy Act, Pub. L. 95–619, 92 Stat. 3206.) Authorities and responsibilities under

[1] The term "Commission" when used in the context of action taken prior to October 1, 1977, refers to the FPC, when used otherwise, the reference is to the FERC.

Section 202(a) of the Federal Power Act were transferred to the Secretary by the Department of Energy (DOE) Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267. See also 10 CFR Part 1000. By letter dated August 17, 1978, FERC staff requested advice as to whether the staff of the Economic Regulatory Administration (ERA) was interested in continued reporting under 18 CFR 2.14. ERA staff now advises that the reporting is of limited value to it, in view of its broad authority to gather all forms of energy information on a mandatory basis, when needed. Consequently, it interposes no objection to discontinuance of the reporting.

The Commission solicits comments on the proposed discontinuance of this reporting, especially as to whether continued reporting of this information is in the public interest and justifies the reporting burden. Comments are also solicited on the merits of a revised reporting system located elsewhere within the Department of Energy.

Any interested person may submit to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than May 17, 1979, data, views, comments or suggestions in writing concerning all or part of the amendment proposed herein. Written submittals will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. The Commission will consider all such written submittals before acting on the matters herein proposed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Submittals to the Commission should indicate the name, title, mailing address, and telephone number of the person to whom communications concerning the proposal should be addressed.

[Administrative Procedure Act, 5 U.S.C. 551 *et seq.*; Federal Power Act, as amended, 16 U.S.C. 791 *et seq.*; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.]

In consideration of the foregoing, the Commission proposes to amend Part 2, Subchapter A, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,
Secretary.

§ 2.14 [Deleted]

1. Part 2, Subchapter A, Chapter I, Title 18, Code of Federal Regulations, is amended by deleting § 2.14

[Docket No. RM79-25]

¶ 32,019 Applications for Licenses for Major Projects—Existing Dams

44 F. R. 24095 (April 24, 1979).

[18 CFR Parts 2, 4, and 16]

Applications for Licenses for Major Projects—Existing Dams; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The proposed rulemaking would amend the Commission's regulations concerning applications for licenses for water power projects under Part I of the Federal Power Act. More specifically, the rulemaking would amend the regulations governing the content of applications for licenses for "major" projects (capacity greater than 1.5 MW) which utilize, or would utilize, the water power potential of existing dams only.

DATES: Written comments must be received on or before May 25, 1979.

ADDRESS: Comments referring to Docket No. RM79-36 should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Mr. Howard Jack, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4269.

SUPPLEMENTARY INFORMATION:

Notice is hereby given that the Federal Energy Regulatory Commission (Commission) proposes to amend certain of its regulations concerning applications for licenses for water power projects under Part I of the Federal Power Act (Act). The amended regulations pertain to applications for licenses for "major" projects (capacity greater than 1.5 MW) which utilize, or would utilize, the water power potential of existing dams only. The regulations therefore govern applications which seek: (1) An initial license [1] for an existing hydroelectric project with total installed and proposed capacity greater than 1.5 MW; (2) a new license [2] for an existing hydroelectric project with total installed and proposed capacity greater than 1.5 MW; or (3) an initial license for a proposed hydroelectric project at an existing dam or dams, with proposed capacity greater than 1.5 MW. The projects in these categories are referred to generically as "major projects—existing dams."

I. Background

Congress provided in Title IV of the Public Utility Regulatory Policies Act (PURPA) component of the National Energy Act for a program whereby the Secretary of Energy will grant loans for feasibility studies and for construction of small hydroelectric projects (capacity of 15 MW or less) located at existing dams. The Commission is charged under Section 405 of PURPA, 92 Stat. 3156, with establishing simple licensing procedures for projects eligible under the PURPA provisions.

In the interest of acting more promptly on all license applications, and in anticipation of the enactment of PURPA, the Commission determined in 1978 to carry out a thorough reform of its requirements and procedures for license applications. The first phase of this reform was instituted in September 1978, with issuance of a rulemaking on the "short-form" license procedures

[1] "Initial license" is defined as the first license issued for a water power project under either the Federal Water Power Act of 1920 or the Federal Power Act.

[2] "New license" is defined as nay license for a water power project that is issued under the Federal Power Act to succeed an initial license for that project, except an annual license issued under Section 15(a) of that Act, 16 U.S.C. § 808(a).

applicable to all "minor" projects (capacity of 1.5 MW or less).[3]

On March 5, 1979, the Commission issued a notice of proposed rulemaking which prescribes general filing requirements and evaluation procedures applicable to both preliminary permit and license applications, and which simplifies the regulations relating specifically to applications for preliminary permits, amendments to permits, and cancellation of permits.[4]

The regulations proposed in this notice subsume the remainder of the projects which fit the criteria of the PURPA provisions and which were not embraced by the "short-form" regulations. Since the equities which warrant streamlined requirements and procedures for proposed hydroelectric projects at existing dams are applicable to existing hydroelectric projects as well, the scope of this rulemaking has been made as inclusive as possible in order to maximize its benefits.

The existing requirements for the types of license applications which fit this rulemaking are scattered through various parts of Title 18 of the Code of Federal Regulations. Substantive requirements applicable to one or all of these applications may be found in §§ 2.80 and 2.81, Appendix A to Part 2, §§ 4.40–4.51, § 16.6, and § 131.2 of Title 18. In following these regulations, a potential applicant faces the prospect of meeting information requirements embodied in at least 12 itemized paragraphs and up to 23 exhibits.

In preparing the amended regulations set forth in this notice, we have attempted in several ways to ease the burden of compliance. First, we have tried to reduce the requested information to the bare minimum that is needed for the Commission to carry out its duties under existing law [5] in an informed and responsible manner. For example, among other superfluous requests for information, the provisions requiring extensive documentation of the nature of the applicant, its authority to file the application, and its compliance with state laws, have been discarded.[6]

Second, we have attempted to consolidate requests for information according to related subject matter. All paragraphs and exhibits requesting information on environmental matters,[7] for instance, have been consolidated into the Exhibit E (environmental report) required under proposed § 4.51(f). Rational organization of the requirements should reduce confusion and redundancy in the materials submitted.

Finally, we have endeavored to minimize the element of subjective interpretation in our requirements by reducing the requests for information, where possible, to simple, objective descriptions of what is desired. Moreover, the services of our staff are

[3] Order No. 11, Docket No. RM78-9, 43 Fed. Reg. 40215 (September 11, 1978). The 1.5 MW capacity criterion was based on the fact that the Commission is authorized under Section 10(i) of the Act, 16 U.S.C. § 803(i), to give less intensive scrutiny to such minor projects. Since the capacity limitation prescribed in PURPA is 15 MW, the first phase of the reform covered only a portion of the projects that would be eligible under the PURPA program.

[4] Docket No. RM79-23, 44 Fed. Reg. 12432 (March 7, 1979). On April 6, 1979, the Commission's Secretary granted a request by the Sierra Club Legal Defense Fund to extend the time for comments on those proposed regulations to April 30, 1979. The regulations proposed in this rulemaking refer to, and may be read in conjunction with, the regulations proposed in Docket No. RM79-23.

[5] Section 405 of PURPA provides that the Commission's simplified licensing procedures must be "consistent with the applicable provisions of law," and that no project covered by the procedures will be exempted from "any requirement applicable to any such project under the National Environmental Policy Act of 1969, the Fish and Wildlife Coordination Act, the Endangered Species Act, or any other provision of Federal law."

[6] See existing § 4.40(b) and § 4.41—Exhibits A—F. These requirements have been distilled to simple statements in the initial portion of the application under proposed § 4.51(a). Since the entire application is subscribed and verified under § 1.16 of our rules, the statements themselves would suffice as evidence. Additional information could be requested in cases where it is needed.

[7] See existing § 2.80, Appendix A to Part 2, § 4.40(k) and (l), and § 4.41—Exhibits H, R, S, V, and W.

offered to assist in overcoming any unavoidable problems of interpretation. We hope that clearer, simpler requirements and a cooperative effort will help us avoid the application deficiencies that have plagued our licensing program in the past.

We now proceed to a description and explanation of the proposed regulations.

II. Description of proposed regulations

§ 4.50 *Applicability and definitions.*

This section states that §§ 4.50 and 4.51 pertain to any application for either an initial license, or a new license, for a major project—existing dam. The section also provides definitions of certain key terms which appear in §§ 4.50 and 4.51. The definition of "major project—existing dam" makes clear that proposed construction or repair with certain environmental consequences will remove an application from the purview of these sections.[8] Finally, the section offers the assistance of the Commission staff in determining whether §§ 4.50 and 4.51 apply to a given project.

§ 4.51 *Contents of application.*

This section contains the specific requirements governing the contents of an application for a license for a major project—existing dam. The requirements are embodied in an initial statement and seven lettered exhibits.

Initial statement

The initial statement provides certain basic information necessary for identification and orientation purposes, including the nature of the application, the names and business addresses of the applicant and its authorized agents, the nature of the applicant, and the name and location of the project. The applicant is also required to state that it has complied with the laws of the State where the project is located with respect to obtaining property rights and the rights to appropriate, divert, and use water for power purposes, and with respect to obtaining authorization to engage in the business of producing, transmitting, and distributing power and any other business necessary to accomplish the purposes of the requested license.[9]

Exhibit A

This exhibit provides a description of the physical structures and features of the project. If the project includes more than one dam and associated facilities, each such discrete development must be described separately. The exhibit also includes a tabulation of any lands of the United States that are enclosed within the project boundary. This tabulation is necessary in order to record accurately the lands which have been reserved from entry, location, or other disposal pursuant to Section 24 of the Act, 16 U.S.C. 818.

Exhibit B

This exhibit provides a statement of project operation and resource utilization. The exhibit calls for a description of the available resource (flow and head) and technical documentation of the manner in which the applicant proposes to utilize that resource for the generation of power. The applicant must also explain how it intends to dispose of the power. Finally, the applicant must describe any plans for future hydroelectric development on the affected stream. The information in this exhibit will assist the Commission in determining whether the applicant's existing or proposed development and operation comport with optimum development of the waterway, as required by Section 10(a) of the Act, 16 U.S.C. 803(a).

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[8] Section 408(b) of PURPA, 92 Stat. 3157, defines "existing dam" as any dam, the construction of which was completed on or before April 20, 1977, and which does not require any construction or enlargement of impoundment structures (other than repairs or reconstruction) in connection with the installation of hydroelectric capacity.

[9] See Section 9(b) of the Act, 16 U.S.C. § 802(b), and fn. 6, *supra*.

Exhibit C

This exhibit provides a construction history and a proposed construction schedule for the project. The construction history, which need only be filed if the applicant is seeking an initial license, calls for a tabulated chronology of construction for the existing project structures and facilities, including the dates of commencement and completion of construction or installation, and the dates of commencement of commercial operation. This information is requested for several reasons. First, if the project is located on a nonnavigable waterway, and the sole possible basis for the Commission's jurisdiction is the fact that the project affects the interests of interstate or foreign commerce, jurisdiction does not attach unless there has been "construction" at the project within the meaning of Section 23(b) of the Act, 16 U.S.C. § 817, at some time subsequent to enactment of the Public Utility Holding Company Act of 1935.[10] Second, if the project is a constructed hydroelectric project located on a navigable waterway, Commission policy may call for backdating of the effective date of the license or retroactive assessment of annual charges to the date of unauthorized construction.[11] Finally, substantial reconstruction may have the effect of bringing to an end an *ad hoc* Congressional authorization for the project which antedated the Federal Water Power Act of 1920.[12] An applicant seeking a license for a proposed project at an existing dam would only be expected to give approximate dates for the dam and any other existing structures.

The proposed construction schedule is required only if new development at the project is proposed. The schedule would aid in a precise understanding of what is being proposed, and would facilitate establishment of a construction timetable in the license, if issued, as required by Section 13 of the Act, 16 U.S.C. 806.

Exhibit D

This exhibit provides a statement of costs and financing. If the applicant seeks a new license for a constructed project, and is not a municipality or a state, it must provide an estimate of the amount that would be payable if the United States exercised its right to take over the project upon expiration of the initial license pursuant to Section 14 of the Act, 16 U.S.C. 807.

If the applicant seeks an initial license, information concerning the original cost of land or water rights and existing project works must be provided. The Commission is required by Section 4(b) of the Act, 16 U.S.C. 797(b), to obtain information on the original cost of a project.

Estimated costs of any proposed new development and estimated annual costs must also be provided, as well as information concerning the value of project power to the applicant and the sources and extent of financing and annual revenues available to meet the estimated costs. This information would enable the Commission to assess the economic and financial viability of the project.

Exhibit E

This exhibit provides a report on the environmental resources of the project, the impacts of the project on those resources, and the proposed measures to mitigate the impacts or to protect and enhance the resources. The information required in this exhibit is, in many respects, less detailed and extensive than the information required by the existing regulations governing applications for all major projects (see fn. 7, *supra*). The less stringent requirements are justified on the basis

[10] *Farmington River Power Co.* v. *FPC*, 455 F.2d 86 (2nd Cir. 1972); *Puget Sound Power & Light Co.* v. *FPC*, 557 F.2d 1311 (9th Cir. 1977).

[11] Opinion No. 357, *Public Service Co. of New Hampshire*, Project No. 2288, 27 F.P.C. 830 (1962); *Central Maine Power Co.* v. *FPC*, 345 F.2d 875 (1st Cir. 1965); *Bangor Hydro-Electric Co.* v. *FPC*, 355 F.2d 13 (1st Cir. 1966); *Niagara Mohawk Power Corp.* v. *FPC*, 379 F.2d 153 (D.C. Cir. 1967).

[12] *Northwest Paper Co.* v. *FPC*, 344 F.2d 47 (8th Cir. 1965); *Minnesota Power & Light Co.* v. *FPC*, 344 F.2d 53 (8th Cir. 1965).

that the significant impacts associated with construction of the dams and creation of the impoundments have already occurred.[13] Sufficient information is required in this multifaceted exhibit [14] to ensure that any further impacts will be identified and taken into account pursuant to the National Environmental Policy Act of 1969 and other applicable law.[15]

The exhibit requires applicants to consult with other local, state, and federal agencies with expertise in environmental matters prior to filing their applications. Under our existing regulations and procedures, other agencies frequently are not even aware that development is being proposed until after the application has been filed with the Commission. Proceedings must often be delayed while agencies consider the effects of projects on their areas of responsbility and fashion recommendations. With preapplication consultation, problem issues will be identified and addressed at an earlier point in the process, and the Commission's own required consultation with other agencies will be expedited.[16]

Exhibit F

This exhibit consists of general design drawings of the principal project works. The drawings must show plans, elevations, profiles, and sections for each structure, and must be accompanied by sufficient information concerning structural strength and stability and other controlling factors to demonstrate that the structures are safe and adequate for their stated functions. See Section 10(c) of the Act, 16 U.S.C. 803(c).

Detailed working drawings showing the precise plans and specifications for proposed project structures are not to be filed with the application, but should be prepared for the purposes of construction and retained after construction is completed as permanent project records.

Exhibit G

The final exhibit is a map of the project. The map must show the geographical location of the project, the physical interrelationships of project works and other features, a project boundary enclosing the project works and all lands and waters necessary for project purposes, and any lands of the United States that are within the project boundary.

III. Other proposed changes and deletions

Besides the described amendments to §§ 4.50 and 4.51, we propose certain other changes to the existing rules and regulations. Section 2.81(a) of our general rules concerning compliance under Part I of the Federal Power Act with the National Environmental Policy Act of 1969 has been amended to reflect the new bifurcated approach to

[13] Proposed § 4.50(b)(5), which defines "major project—existing dam," makes clear that these provisions will not apply if proposed repair or reconstruction of the existing dam would result in a significant increase in the normal maximum surface area or normal maximum surface elevation of an existing impoundment, or if any new development or change in project operation would result in a significant environmental impact.

[14] The exhibit must include reports on water use and quality; fish, wildlife, and botanical resources; historical and archeological resources; recreation resources; and land management and aesthetics.

[15] See, e.g. *Udall* v. *FPC*, 387 U.S. 428 (1967); *Scenic Hudson Preservation Conference* v. *FPC*, 354 F.2d 608 (2nd Cir. 1965), *cert. den.* 384 U.S. 941 (1966). See also Sections 10(a) and 18 of the Federal Power Act, 16 U.S.C. 803(a) and 811; the National Historic Preservation Act, 16 U.S.C. 470 *et seq.*; the Fish and Wildlife Coordination Act, 16 U.S.C. 661 *et seq.*; the Anadromous Fish Conservation Act, 16 U.S.C. 757a *et seq.*; the Wild and Scenic Rivers Act, 16 U.S.C. 1271 *et seq.*; the Endangered Species Act, 16 U.S.C. 1531 *et seq.*; and the Federal Water Pollution Control Act, as amended, 33 U.S.C. 1251 *et seq.*

[16] Several statutes, including PURPA, require the Commission to consult with other agencies. Section 405 of PURPA provides that, prior to issuing a license for a project which fits the PURPA criteria, the Commission must "provide an opportunity for consultation with the Council on Environmental Quality and the Environmental Protection Agency with respect to the environmental effects of such project." This duty will be carried out in accordance with our established procedures for consultation during the license application review process. Moreover, in certain circumstances, other agencies may have concurrent jurisdiction with respect to authorization of a project. Prior consultation by applicants will facilitate coordination with these other agencies.

environmental reporting based on the nature of the application.

Section 16.6 of the regulations governing applications for new licenses has been deleted. Most of the provisions of § 16.6 have been incorporated in the amended § 4.51. The provisions of § 16.6(e), which requires a licensee-applicant who is not a municipality or a state to file a statement on the effect that takeover by the United States or issuance of a license to another applicant would have upon the supply of electric energy to the system with which it is interconnected, the rates charged its customers, its financial condition, and taxes collected by local, state, and federal governments, have been eliminated entirely. In a situation where there is a competing application, or a recommendation for federal takeover may be desirable, this information could be requested as a supplemental filing. If such situations become commonplace, the requirement could be reinstated in the regulations.

IV. Written comment procedures

The Commission invites interested persons to submit written comments on the matters proposed in this notice. An original and 14 copies of such comments should be filed with the Commission by May 25, 1979. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. All comments should refer to Docket No. RM79-36.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426. The Commission will consider all timely comments before acting on the matters proposed in this notice.

(Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Public Utility Regulatory Policies Act, Pub. L. 95-617, 92 Stat. 3117 *et seq.*; and Executive Order 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to amend Part 2 of Subchapter A and Parts 4 and 16 of Subchapter B, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Lois D. Cashell,
Acting Secretary.

(A) Section 2.81(a) is amended to read as follows:

§ 2.81 Compliance with the National Environmental Policy Act of 1969 under Part I of the Federal Power Act.

(a) Any application under Part I of the Federal Power Act for a license for a major hydroelectric project (capacity greater than 2,000 hp) which is completely unconstructed, or which includes a proposed change in the existing state of project works or project operation which would result in a significant increase in the normal maximum surface area or normal maximum surface elevation of an existing impoundment, or in a significant environmental impact, must include an environmental report which conforms to the requirements of § 4.41— Exhibit W, § 2.80, and Appendix A of Part 2 of this chapter. Any application for a license for a major project—existing dam as defined in § 4.50(b) must include an environmental report which conforms to the requirements of § 4.51(f) (Exhibit E). Any application for surrender or amendment of a license that proposes a change in the existing state of project works or project operation which would result in a significant increase in the normal maximum surface area or normal maximum surface elevation of an exisiting impoundment, or in a significant environmental impact, must include an environmental report which conforms to the requirements of § 2.80 and Appendix A of Part 2 of this chapter. Any application for surrender or amendment of a license that proposes a change in the existing state of project works or project operation which would not have any of the effects described above must include an environmental report which conforms to the

requirements of § 4.51(f). A prospective applicant may seek advice from the Commission staff concerning whether any proposed change in the existing state of project works or project operation would result in a significant increase in the normal maximum surface area or normal maximum surface elevation of an existing impoundment, or in a significant environmental impact [see § 4.31(g)].

* * * * *

(B) The center heading that appears above § 4.50 and §§ 4.50 and 4.51 are amended by deleting the existing center heading sections and replacing them with the following:

Application for License for Major Project--Existing Dam

§ 4.50 *Applicability and definitions.*

(a) The provisions of §§ 4.50 and 4.51 pertain to any application for either an initial license, or a new license, for a major project—existing dam.

(b) For the purposes of these sections:

(1) "Dam" means any structure for impounding water;

(2) "Existing dam" means any dam that has been completely constructed;

(3) "Existing impoundment" means any body of water that an existing dam impounds;

(4) "Initial license" means the first license issued for a water power project under either the Federal Water Power Act of 1920 or the Federal Power Act;

(5) "Major project—existing dam" means a licensed or unlicensed, existing or proposed water power project that, as proposed to be licensed:

(i) Would have a total installed generating capactiy of more than 2,000 hp (1.5 MW);

(ii) Would not use the water power potential of any dams except existing dams;

(iii) Does not include any proposed repair or reconstruction of an existing dam that would result in a significant increase in the normal maximum surface area or the normal maximum surface elevation of an existing impoundment; and

(iv) Does not include any proposed new development or change in project operation that would result in a significant environmental impact;

(6) "New development" means any construction, installation, repair, reconstruction, or other change in the existing state of project works or appurtenant facilities; and

(7) "New license" means any license for a water power project that is issued under the Federal Power Act to succeed an initial license for that project, except an annual license issued under Section 15 of the Federal Power Act.

(c) A prospective applicant for a major license—existing dam may seek advice from the Commission staff regarding the applicability of these sections to its project [see § 4.31(g)], including the determinations whether any proposed repair or reconstruction of an existing dam would result in a significant increase in the normal maximum surface area or the normal maximum surface elevation of an existing impoundment, or whether any proposed new development or change in project operation would result in a significant environmental impact.

§ 4.51 Contents of application.

Each application for a license for a major project—existing dam must include the following initial statement and lettered exhibits containing the information and documents specified:

(a) Initial statement:

Before the Federal Energy Regulatory Commission

Application for License for Major Project—Existing Dam

1. [Name of applicant] applies to the Federal Energy Regulatory Commission for a [license or new license, as appropriate] for the [name of project] water power project, as described in the attached exhibits. [(If a project number has been assigned previously): The project is currently designated as FERC Project No. [project number].]

2. The location of the project is:

State or territory: _____

County: _____

Township or nearby town: _____

Stream or other body of water: _____

3. The exact name and business address of the applicant are:

_____

_____

_____

The exact name and business address of each person authorized to act as agent for the applicant in this application are:

_____

_____

_____

4. [Name of applicant] is a [citizen, association of citizens, domestic corporation, municipality, or state, as appropriate].

5. [Name of applicant] has complied with the laws of [State or territory where the project is located] with respect to obtaining property rights and the rights to appropriate, divert, and use water for power purposes, and with respect to obtaining authorization to engage in the business of producing, transmitting, and distributing power and any other business necessary to accomplish the purposes of the requested license.

(b) *Exhibit A* is a description of the project. If the project includes more than one dam and associated facilities, the associated component parts must be described together as a discrete development. The description must contain:

(1) The physical composition, dimensions, general configuration, and condition (where applicable) of any dams, spillways, penstocks, powerhouses, tailraces, or other structures, whether existing or proposed, to be included as part of the project;

(2) The normal maximum surface area and normal maximum surface elevation (mean sea level), gross storage capacity, and usable storage capacity of any impoundments to be included as part of the project;

(3) The number, type, rated capacity, and condition (where applicable) of any turbines or generators, whether existing or proposed, to be included as part of the project;

(4) The number, length, voltage, interconnections, and condition (where applicable) of any primary transmission lines, whether existing or proposed, to be included as part of the project [see 16 U.S.C. 796(11)];

(5) The specifications and condition (where applicable) of any additional mechanical, electrical, and transmission equipment appurtenant to the project; and

(6) All lands of the United States that are enclosed within the project boundary described under paragraph (h) of this section (Exhibit G), identified and tabulated by legal subdivisions of a public land survey of the affected area or, in the absence of a public land survey, by the best available legal description. The tabulation must show the total acreage of the lands of the United States within the project boundary.

(c) *Exhibit B* is a statement of project operation and resource utilization. If the project includes more than one dam and associated facilities, the information must be provided separately for each such discrete development. The statement must contain:

(1) A statement whether operation of the power plant will be manual or automatic, an estimate of the annual plant factor, and a statement of how the project will be operated during periods of low, average, and high stream flow;

(2) An estimate of the dependable capacity and average annual energy production in kilowatt-hours (or a mechanical equivalent), supported by the following data:

(i) The minimum, average, and maximum flow in cubic feet per second of the stream or other body of water at the power plant intake or point of diversion, with a specification of any

adjustments made for evaporation, leakage, minimum flow releases (including duration of releases), or other reductions in available flow, a flow duration curve indicating the period of record and the gaging stations used in deriving the curve, and a specification of the period of critical streamflow used to determine the dependable capacity;

(ii) An area-capacity curve showing the gross storage capacity and usable storage capacity of the impoundment, with a rule curve showing the proposed operation of the impoundment and how the usable storage capacity is to be utilized;

(iii) The estimated hydraulic capacity of the plant (maximum flow through the plant) in cubic feet per second;

(iv) A tailwater rating curve; and

(v) A curve showing plant capability versus head and specifying maximum, normal, and minimum heads;

(3) A statement, with load curves and tabular data, if necessary, of the manner in which the power generated at the project is to be utilized, including the amount of power to be used on-site, if any, the amount of power to be sold, and the identity of any proposed purchasers; and

(4) A statement of the applicant's plans, if any, for future development of the project or of any other existing or proposed hydroelectric project on the stream or other body of water, indicating the approximate location and estimated installed capacity of the proposed developments.

(d) *Exhibit C* is a construction history and proposed construction schedule for the project. The construction history and schedule must contain:

(1) If the application is for an initial license, a tabulated chronology of construction for the existing project structures and facilities described under paragraph (b) of this section (Exhibit A), specifying for each structure or facility, to the extent possible, the actual or approximate dates of: (i) commencement and completion of construction or installation; (ii) commencement of commercial operation; and (iii) any additions or modifications other than routine maintenance (approximate dates must be identified as such); and

(2) If any new development is proposed, a proposed schedule describing the necessary work and specifying the intervals following issuance of a license when the work would be commenced and completed.

(e) *Exhibit D* is a statement of costs and financing. The statement must contain:

(1) If the application is for an initial license, a tabulated statement providing the actual or approximate original cost of: (i) any land or water rights necessary to the existing project; and (ii) each existing structure and facility described under paragraph (b) of this section (Exhibit A) (approximate costs must be identified as such);

(2) If the applicant is a licensee applying for a new license, and is not a municipality or a State, an estimate of the amount which would be payable if the project were to be taken over pursuant to Section 14 of the Federal Power Act upon expiration of the license in effect [see 16 U.S.C. 807], including (i) fair value; (ii) net investment; and (iii) severance damages;

(3) If the application includes proposals for any new development, a statement of estimated costs, including:

(i) The cost of any land or water rights necessary to the new development; and

(ii) The cost of the new development work, with a specification of: (A) quantity, unit costs, and total costs of each item; (B) indirect construction costs such as costs of construction equipment, camps, and commissaries; and (C) overhead construction costs, such as costs of engineering, supervision of construction, legal expenses, taxes, allowance for funds used during construction, administrative or general expenses, and, if necessary, contingencies;

(4) A statement of the estimated annual costs of the total project as proposed, including: (i) Cost of capital (equity and debt); (ii) local, state, and federal taxes; (iii) depreciation or amortization; and (iv) operation and maintenance expenses, including interim

replacements, insurance, and administrative or general expenses;

(5) A statement of the value to the applicant of project power in mills per kilowatt-hour (or per mechanical energy equivalent), supported by a showing of either the cost of obtaining an equivalent amount of power from alternative sources or the contract price for sale of the power; and

(6) A statement specifying the sources and extent of financing and annual revenues available to the applicant to meet the costs identified in paragraphs (e)(3) and (4) of this section.

(f) *Exhibit E* is an environmental report. The report must be prepared in consultation with local, state, and federal agencies with expertise in environmental matters. The names and addresses of these agencies may be obtained from the Director, Division of Licensed Projects. Information provided in the report must be organized and referenced according to the itemized subparagraphs below. If a request for information is not applicable, the applicant must explain briefly why it does not apply. The environmental report must contain the following elements:

(1) *General description of locale.* The applicant must provide a general description of the environment of the project and its immediate vicinity. The description must include general information concerning climate, topography, vegetative cover, land development, population size and density, and any other subjects helpful to an understanding of the setting.

(2) *Report on water use and quality.* The applicant must provide a report on the consumptive use of project waters and the impact of the project on water quality. The report must be prepared in consultation with the state and federal agencies with responsibility for management of water quality in the affected stream or other body of water. Consultation must be documented by appending to the report copies of all written communications between the applicant and the agencies consulted. The report must contain:

(i) A description (including specified volume over time) of existing and proposed uses of project waters for irrigation, domestic water supply, steam generation, plant cooling, industrial, and other consumptive purposes;

(ii) A description of existing water quality in the project impoundment and downstream;

(iii) A description of any minimum flow releases (specifying rate of flow in cubic feet per second (cfs) and duration), changes in the design of project works, changes in project operation, or other measures recommended by specified state or federal agencies for the purpose of protecting or improving water quality, including measures to minimize the short-term impacts to water quality of any proposed new development of project works;

(iv) A statement of the measures taken currently or proposed by the applicant for the purpose of protecting or improving water quality, including: (A) a description of any existing measures that the applicant proposes to continue; (B) specification of any of the recommended measures described under paragraph (f)(2)(iii) of this section, that the applicant proposes to implement, with an explanation of the applicant's nonacceptance or the remaining recommended measures, if any; and (C) a description of any different or additional measures that the applicant proposes to implement;

(v) A description of the anticipated net impact on water quality of continued operation of the project; or of proposed new development of project works or changes in project operation; and

(vi) As an appendix, either: (A) a copy of a water quality certification (or statement that such certification is waived) issued pursuant to Section 401 of the Federal Water Pollution Control Act, as amended [see 33 U.S.C. 1341], by the U.S. Environmental Protection Agency or the state agency with authority to administer the section 401 program; or (B) a copy of a dated letter from the applicant to the appropriate agency requesting certification under Section 401.

(3) *Report on fish, wildlife, and botanical resources.* The applicant must provide a report on the fish, wildlife, and botanical resources in the vicinity of the project and the impact of the project on those resources. The report must be prepared in consultation with any state agency with responsiblity for fish, wildlife, or botanical resources, the U.S. Fish and Wildlife Service, the National Marine Fisheries Service (if the project may affect anadromous fish resources subject to that agency's jurisdiction), and any other state or federal agency with managerial authority over any part of the project lands. Consultation must be documented by appending to the report copies of all written communications between the applicant and the agencies consulted. The report must contain:

(i) A description of the fish, wildlife, and botanical resources of the project and its vicinity, and of downstream areas affected by the project, including identification of any species listed as threatened or endangered by the U.S. Fish and Wildlife Service [see 50 CFR 17.11 and 17.12];

(ii) A description of any measures or facilities recommended by specified state or federal agencies for the mitigation of impacts on fish, wildlife, and botanical resources, or for the protection or improvement of such resources;

(iii) A statement of the measures or facilities that exist or are proposed by the applicant for the mitigation of impacts on fish, wildlife, and botanical resources, or for the protection or improvement of such resources, including: (A) a description of any existing measures or facilities that would be continued or maintained; (B) specification of any of the recommended measures or facilities described under paragraph (f)(3)(ii) of this section, that the applicant proposes to implement or construct, with an explanation of the applicant's nonacceptance of the remaining recommended measures or facilities, if any; and (C) a description of any different or additional measures or facilities that the applicant proposes to implement or construct;

(iv) A description of the anticipated net impacts on fish, wildlife, and botanical resources of continued operation of the project, or of proposed new development of project works or changes in project operation; and

(v) The following materials and information regarding the measures and facilities identified under subparagraph (3)(iii) as either existing or proposed for implementation or construction:

(A) Functional design drawings of any fish passage and collection facilities, indicating whether the facilities depicted are existing or proposed (these drawings must conform to the specifications of § 4.32 regarding dimensions of full-size prints, scale, and legibility);

(B) A description of operation and maintenance procedures for any measures or facilities, indicating whether the measures or facilities are existing or proposed;

(C) An implementation and construction schedule for any proposed measures or facilities, showing the intervals following issuance of a license when implementation of the measures or construction of the facilities would be commenced and completed;

(D) An estimate of the costs of construction, operation, and maintenance of any proposed facilities, and of implementation of any measures;

(E) A statement of the sources and extent of financing for any proposed measures or facilities, including a description and explanation of any agreements regarding financing of the measures or facilities by others; and

(F) A map or drawing showing by the use of shading, cross-hatching, or other symbols the identity and location of any measures or facilities, indicating whether each measure or facility is existing or proposed (the map or drawing may be consolidated with other maps or drawings required in this exhibit and must conform to the specifications of § 4.32 regarding dimensions of full-size prints, scale, and legibility).

(4) *Report on historical and archeological resources.* The applicant

must provide a report on the historical and archeological resources in the project area and the impact of the project on those resources. The report must be prepared in consultation with the State Historic Preservation Officer and the U.S. Heritage Conservation and Recreation Service. Consultation must be documented by appending to the report copies of all written communications between the applicant and the agencies consulted. The report must contain:

(i) Identification of any sites either listed or determined to be eligible for inclusion in the National Register of Historic Places that are located in the project area, or that would be affected by operation of the project or by new development of project facilities (including facilities proposed in this exhibit);

(ii) A description of any measures recommended by specified state or federal agencies for the purpose of locating, identifying, and salvaging historical or archaeological resources that would be affected by operation of the project, or by new development of project facilities (including facilities proposed in this exhibit), together with a statement of the applicant's position regarding the acceptability of the recommendations; and

(iii) The following materials and information regarding the survey and salvage activities described under paragraph (f)(4)(ii) of this section:

(A) A schedule for the activities, showing the intervals following issuance of a license when the activities would be commenced and completed;

(B) An estimate of the costs of the activities; and

(C) A statement of the sources and extent of financing for the activities, including a description and explanation of any agreements regarding financing of the activities by others.

(5) *Report on recreation resources.* The applicant must provide a report on existing and proposed recreation facilities and opportunities at the project. The report must be prepared in consultation with local, State, and regional recreation agencies and planning commissions, the U.S. Heritage Conservation and Recreation Service, and any other State or Federal agency with managerial authority over any part of the project lands. Consultation must be documented by appending to the report copies of all written communications between the applicant and the agencies consulted. The report must contain:

(i) A description of any existing recreational facilities at the project, indicating whether the facilities are available for public use;

(ii) An estimate of existing and potential recreational use of the project area in daytime and overnight visits;

(iii) A description of any measures or facilities recommended by specified local, State, regional, or Federal agencies for the purposes of creating or enhancing recreation opportunities at the project and its vicinity (including opportunities for the handicapped), and for the purpose of ensuring the safety of the public in its use of project lands and waters;

(iv) A statement of the measures or facilities proposed by the applicant for the purpose of creating or enhancing recreation opportunities at the project and its vicinity, and for the purpose of ensuring the safety of the public in its use of project lands and waters, including: (A) specification of any of the recommended measures or facilities described under subparagraph (f)(5)(iii) of this section, that the applicant proposes to implement or construct, with an explanation of the applicant's nonacceptance of the remaining measures or facilities, if any; and (B) a description of any different or additional measures or facilities that the applicant proposes to implement or construct; and

(v) The following materials and information regarding the measures and facilities identified under paragraphs (f)(5)(i) and (iv) of this section as either existing or proposed for implementation or construction:

(A) Identification of the entities responsible for operating and

maintaining any existing or proposed facilities;

(B) A schedule for construction of any proposed facilities, showing the intervals following issuance of a license when construction of the facilities would be commenced and completed;

(C) An estimate of the costs of construction and maintenance of any proposed facilities;

(D) A statement of the sources and extent of financing for any proposed facilities, including a description and explanation of any agreements regarding financing of the facilities by others; and

(E) A map or drawing showing by the use of shading, cross-hatching, or other symbols the identity and location of any facilities, indicating whether each facility is existing or proposed (the map or drawing may be consolidated with other maps or drawings required in this exhibit and must conform to the specifications of § 4.32 regarding dimensions of full-size prints, scale, and legibility).

(6) *Report on land management and aesthetics.* The applicant must provide a report on the management of land within the proposed project boundary and the protection of the scenic values of the project. The report must be prepared following consultation with local and state zoning and land management authorities and any federal agency with managerial authority over any part of the project lands. Consultation must be documented by appending to the report copies of all written communications between the applicant and the authorities consulted. The report must contain:

(i) A description of existing development and use of project lands and all other lands abutting the project impoundment;

(ii) A description of the measures proposed by the applicant, following consideration of the Commission's "Guidelines for the Protection of Natural, Historic, Scenic, and Recreational Values in the Design and Location of Rights-of-Way and Transmission Facilities" [see 44 F.P.C. 1496], to ensure that proposed project works, rights-of-way, access roads, and other topographic alterations blend, to the extent possible, with the surrounding environment;

(iii) A statement, including an analysis of costs and other constraints, of the applicant's ability to provide a buffer zone around all or any part of the impoundment, for the purpose of ensuring public access to project lands and waters and protecting the aesthetic values of the impoundment shoreline;

(iv) A description of the applicant's policy, if any, with regard to permitting development of piers, docks, boat landings, bulkheads, and other shoreline facilities on project lands and waters; and

(v) Sufficient maps, drawings, or photographs to show the location and nature of the measures proposed under subparagraph (6)(ii) to ensure that structures and other topographic alterations blend with the surrounding environment (maps or drawings may be consolidated with other maps or drawings required in this exhibit and must conform to the specifications of § 4.32 regarding dimensions of full-size prints, scale, and legibility).

(7) *List of literature.* The applicant must provide a list of all publications, reports, and other literature which were cited or otherwise utilized in the preparation of any part of the environmental report.

(g) *Exhibit F* consists of general design drawings of the principal project works described under paragraph (b) of this section (Exhibit A). The drawings must conform to the sepcifications of § 4.32 and must indicate whether each structure depicted is existing or proposed. Detailed working drawings showing the precise plans and specifications for proposed structures should not be filed with the application, but should be prepared for the purposes of construction and, if a license is issued and construction ensues, retained as permanent project records. The general design drawings required under this paragraph must show plans (overhead

view), elevations (front view), profiles (side view), and sections for each principal project work. The drawings must be accompanied by sufficient information relating to composition and competency of foundations and other structures, gradation of filter and riprap material, design strength and ultimate strength of concrete and steel, stress and stability analyses, the project design flood (and Standard Project Flood or Probable Maximum Flood, if different from the design flood) used for stability analysis, spillway rating curves, water levels, and other controlling factors to demonstrate that the structures are safe and adequate to fulfill their stated functions.

(h) *Exhibit G* is a map of the project. The map must conform to the specifications of § 4.32. If more than one sheet is used, the sheets must be numbered consecutively and each sheet must bear a small inset sketch showing the entire project (or development) and indicating the portion depicted on the sheet. The map must show:

(1) *Location of the project and principal features.* The map must show the location of the project as a whole with reference to the affected stream or other body of water and, if possible, to a nearby town or any other permanent monuments or objects that can be noted on the map and recognized in the field. The map must also show the relative locations and physical interrelationships of the principal project works and other features described under paragraph (b) of this section (Exhibit A).

(2) *Project boundary.* The map must show a project boundary enclosing all of the principal project works and other features described under paragraph (b) of this section (Exhibit A). The boundary must enclose only those lands necessary for operation and maintenance of the project and for other project purposes such as recreation, shoreline control, or protection of environmental resources [see paragraph (f) of this section (Exhibit E)]. Existing residential, commercial, or other structures may be included within the boundary only to the extent that underlying lands are needed for project purposes (e.g. for flowage, recreation, shoreline control, or protection of environmental resources).

If the boundary is on lands covered by a public land survey, ties must be shown on the map at sufficient points to permit accurate plotting of the position of the boundary relative to the lines of the public land survey. If the lands are not covered by a public land survey, the best available legal description of the boundary must be provided, including distances and directions from fixed monuments or physical features. The boundary must be described as follows:

(i) Impoundments. The boundary around a project impoundment may be described by any of the following: (A) contour lines (preferred method); (B) specified courses and distances (metes and bounds); (C) if the project lands are covered by a public land survey, lines upon or parallel to the lines of the survey; or (D) any combination of the above methods. Except as deviations may be necessary in describing the boundary according to the above methods, or where additional lands are necessary for project purposes such as recreation, shoreline control, or protection of environmental resources, the boundary must be located no more than 200 feet (horizontal measurement) from the exterior margin of the reservoir (defined by the normal maximum surface elevation).

(ii) Continuous features. The boundary around linear ("continuous") project features such as access roads, transmission lines, and conduits may be described by specified distances from center lines or offset lines of survey. The width of such corridors must not exceed 200 feet unless good cause is shown for a greater width. Several sections of a continuous feature may be shown on a single sheet, with information showing the sequence of contiguous sections.

(iii) Noncontinuous features. The boundary around noncontinuous project works such as dams, spillways, and powerhouses may be described by: (A) contour lines; (B) specified courses and distances; (C) if the project lands are

covered by a public land survey, lines upon or parallel to the lines of the survey; or (D) any combination of the above methods. The boundary should enclose only those lands that are necessary for safe and efficient operation and maintenance of the project, or for other specified project purposes such as recreation or protection of environmental resources.

(3) *Federal lands.* The map must show any lands of the United States (including reservations) that are within the project boundary. The lands must be identified by legal subdivisions of a public land survey of the affected area (a protraction of identified township and section lines is sufficient for this purpose). In the absence of a public land survey, the location of lands of the United States must be shown by distances and directions from fixed monuments or physical features. When a Federal survey monument or a Federal bench mark will be destroyed or rendered unusable by the construction of project works, at least two permanent, marked, witness monuments or bench marks must be established at accessible points. The map must show the location (and elevation, for bench marks) of the survey monument or bench mark which will be destroyed or rendered unusable, as well as of the witness monuments or bench marks. Connecting courses and distances from the witness monuments or bench marks to the originals must also be shown.

(c) Section 16.6 is deleted in its entirety.

(D) The Secretary shall cause prompt publication of this notice to be made in the **Federal Register**.

[Docket No. RM79-36]

¶ 32,020 Budget-Type Applications for Gas-Purchase Facilities

44 F. R. 24103 (April 24, 1979).

Proposed Rulemaking Respecting Budget-Type Applications for Gas-Purchase Facilities

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The proposed rule would amend § 157.7 of the Federal Energy Regulatory Commission's regulations under the Natural Gas Act to (1) raise the current financial limitations for the submission of budget-type applications; (2) expand the current definition of the gas facilities involved; and (3) change the submission times for such applications to a calendar year basis. These changes are proposed in order to facilitate the Commission's action on these applications. The changes are being undertaken in light of circumstances which have come about since the existing subpart was first promulgated. In addition, the proposed rule would also delete subpart 2.58 of the Commission's regulations as surplusage.

DATES: Written comments must be received on or before May 25, 1979.

ADDRESS: Comments, referencing Docket No. RM79–37 should be addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Mr. Francis Markulin, Office of Pipeline and Producer Regulation, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275–4349.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) proposes to amend § 157.7(b) of its regulations. The amendment would revise the definition of "Gas-purchase facilities", increase the maximum total annual and single-project cost limitations for such facilities, and provide a calendar-year basis for certificate authority. The Commission also proposes to delete § 2.58 of its regulations and provide for the periodic review of the cost limitations of § 157.7(b).

Background

Since its inception in 1956, the "budget-type" application procedure has served as a vehicle whereby the Commission can expeditiously certify the construction of minor installations of certain facilities. This procedure, with its time-saving features, has shown itself to be particularly useful in authorizing the construction of "gas-purchase" facilities—facilities necessary to connect independent producers or other similar sellers of natural gas to purchasers for resale in interstate commerce. The procedure for applying for a budget-type certificate for such facilities, as well as the limitations under which the certificate will be granted, are set forth in § 2.58 and § 157.7(b) of the Commission's Regulations. The limits encompass both the type of facilities involved and the amount to be expended for their construction.

The amounts which may be expended for budget-type certificates for gas-purchase facilities were last revised in January 1975 (FPC Order No. 522, Docket No. RM75–2). Since that time, construction costs have increased to the extent that fewer construction projects may be completed under the threshold provisions. In addition, Commission experience, coupled with recent changes in the law, require a re-evaluation of the facilities which should be included within the scope of budget applications for the construction of gas-purchase facilities.

Summary of Proposal

The current Regulations provide that the total estimated cost of gas-purchase facilities proposed in a budget-type application is not to exceed 2 percent of the applicant's gas plant account (Account 101 of the Uniform System of Accounts Prescribed for Natural Gas Companies) or $12 million, whichever is the lesser, except that an applicant with less than $7.5 million in such a gas plant account may have a total gas-purchase facility budget amount of $150,000. (§ 157.7(b)(1)(i).) Furthermore, under the current regulations the cost of gas-purchase facilities for any single onshore project must not exceed 25 percent of the total budget amount or $1.5 million, whichever is the lesser, and the cost for any single offshore project must not exceed $2.5 million or the total budget amount, whichever is the lesser. (§ 157.7(b)(1)(ii).) To increase the effective use of budget-type authorizations, the Commission proposes to increase these total annual and single-project cost limitations.

Since the last revision of the cost limitations for gas-purchase facilities in January 1975, the cost of constructing facilities has increased. The increase is due to inflation and an increase in the real cost of constructing pipelines. Accordingly, an increase in the total budget and individual project limits appears warranted. Therefore, the Commission proposes to increase the dollar budget limitations of both § 157.7(b)(1)(i) and § 157.7(b)(1)(ii). These increases are based upon Commission experience and considerations of economic changes which have occurred to date,[1] and which may reasonably be expected to occur in the near future.[2]

The $12 million and 2 percent limitations of § 157.7(b)(1)(i) would, under this proposal, be raised to $20 million and 3 percent respectively. This will permit companies to more effectively utilize the gas-purchase budget certificates than present limits now permit. Consistent with this increase, it is proposed that the limit for pipelines with small plant investments be raised to allow a total gas purchase budget of $500,000, rather than the current limit of $150,000. This increase, predicated upon Commission experience since the revisions of 1975, would permit greater use of the budget-type certificate process by smaller companies, while not permitting any change in the character of the regulated operations. In that the $150,000 figure was predicated upon 2 percent of $7.5 million plant investment; the use of $500,000 and a 3 percent figure yields a plant investment figure of $16 and two-thirds million. The regulation would be changed to reflect this increase.

It is proposed that with respect to single projects the present $1.5 million limit for onshore projects and the $2.5 million limit for offshore projects (§ 157.7(b)(1)(ii)) be increased to $2.5 million and $3.5 million, respectively, to reflect increased project costs. This increase should eliminate certificate filings for routine gas-purchase projects and provide additional flexibility to the

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[1] Among the sources used in this regard are: construction cost estimates included in pipeline certificate applications, completion reports filed under § 157.20(a) of the Commission's Regulations, actual construction costs included in pipeline "Section 4" rate changes, Bureau of Labor Statics Wholesale Price Index for industrial commodities, *The Handy-Whitman Index of Public Utility Construction Costs* and *The Engineer News—Record Construction Cost Index*.

The Handy-Whitman Index of Public Utility Construction Costs, Bull. No. 108 (1978), indicates that the inflation factor for total transmission plant for the South Cental region of the United States has increased by about 40 percent for the period from January 1975 through June 1978. *Id.* at Table G–4, pp. 23–24. It should also be noted that the Consumer Price Index for all items during the period January 1975 to January 1978 has increased from 156.1 to 186.9, an increase of 30.8 percent. These increases are relative to costs. With respect to the *Handy-Whitman Index*, the test year is 1949 with a base of 100, and with respect to the Consumer Price Index, the test year is 1967 with a base of 100.

[2] *The Engineer News-Record Construction Cost Index* for January 11, 1979 reports a current inflationary rate in general construction of about 7.2% per year; *see also Economic Report of the President* at 92–93 (Jan. 1979) (rate of growth of consumer prices estimated to be less than 7.5% over the 4 quarters of 1979 and an annual rate of slightly under 7% by the end of the year).

larger pipeline companies in the planning of their construction programs without jeopardizing the concept of minor projects. To further this purpose, it is also proposed that § 157.7(b)(1)(ii) be amended so that there would be no individual project cost limit for projects of up to $500,000 for companies having a gas plant investment of up to $16 and two-thirds million.

It is further proposed that the Commission undertake a periodic view of the threshold levels of §§ 157.7(b)(1)(i) and 157.7(b)(1)(ii). The purpose of this review would be to re-examine existing budget thresholds on a timely basis. The result would be a determination of whether any adjustment to the threshold levels would be warranted. Periodic review would insure that the budget application process kept pace with the needs of the Commission and prevailing industry practices. It would have the added advantage of insuring that the Commission has before it the data necessary with which to make a timely proposal for change.

The mechanism whereby the Commission would inaugurate the periodic review would be by administrative order directing staff to conduct a review of budget thresholds every two years. The analysis would be conducted by the Commission's Office of Pipeline and Producer Regulation and would be one which considered all relevant factors including, but not limited to, the use of budget authorizations, the size and nature of waiver requests, potential rate impact, and industry national or regional trends. The analysis, with any Staff recommendation, would be presented to the Commission. The result would be either a notice for comments preparatory to amending the regulations or no action respecting a change to the budget limitations.

The facilities for which a gas-purchaser budget-type application may be filed are defined under § 157.7(b)(4) as being:

> facilities, subject to the jurisdiction of the Commission, necessary to connect the facilities of an independent producer or other similar seller, authorized by this Commission to make a sale of gas to a gas purchaser for resale in interstate commerce, with the system of the gas purchaser or the system of another natural gas company authorized to transport such gas for the account of, or for the exchange of such gas with, the gas purchaser * * *.

By excluding facilities for the production of gas in which a gas purchaser holds an ownership interest, this definitional limitation has caused needless complexity in the application of § 157.7(b). In addition, the definition, as presently worded, does not account for recent changes in the law brought about because of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621.

Many pipeline companies are engaged in the production of gas. Under the existing definition of gas-purchase facilities such companies are unable to attach supplies in which they have an ownership interest, since the existing definition provides that facilities may be constructed only to connect with the facilities of an independent producer or other similar seller authorized by the Commission to make a sale of gas to a gas purchaser for resale in interstate commerce. Further, it appears that a competitive disadvantage exists for such pipeline companies because, as gas-purchase facilities are presently defined, such pipeline companies are not allowed to attach facilities to take gas which they themselves own. Delays which may be caused by the necessity of the pipeline company's having to file separate certificate applications authorizing such attachments may result in drainage from adjacent wells or in the flaring of the gas where wells contain both oil and gas reserves.

The Commission proposes to amend § 157.7(b)(4) to expand the definition of facilities for which a budget-type application may be made to include facilities to attach a pipeline company's own production. The proposed amendments also provide that facilities to connect pipeline-owned gas acquired through company development and production, acquired in place, or developed and produced with other

companies, would also be included. As a result of this proposed expansion of the definition of gas-purchase facilities, pipeline companies with ownership interests in gas wells will be relieved of the cost and burden of multiple certificate filings for authorization to attach gas wells to receive their own reserves, and the Commission will be relieved of processing and considering such multiple filings for such routine facilities. As a result of this change the label "gas purchase" used throughout § 157.7(b) would be amended to read "gas supply".

In addition to the restriction barring the connection of gas facilities to receive pipeline-owned reserves, the qualification that the seller must be one who is "authorized by this Commission to make a sale of gas to a gas purchaser" does not comport with the provisions of the NGPA to the extent that the NGPA allows such sales without Commission authorization. For this reason it is proposed that the restriction be removed. Failure to do this would severely limit the scope of facilities for which a budget-type certificate could be granted.

Further, it is proposed that § 157.7(b) be amended to provide that all budget-type applications authorizing under that section be on a calendar-year basis. Under existing regulations most authorizations are effective for a 12-month period from the date of authorization or from a specific requested date. Authorizations made for a calendar year would reduce the administrative workload of the Commission by permitting consideration and action on all requests in a limited time span. In addition, such authorizations would permit the evaluation of all budget completion reports on a comparable basis and within a reasonable time period. This proposal would require filing of applications for a given year by October 1 of the previous year to provide time for Commission review.

Should the proposed change to a calendar-year authorization take place, a transition rule will be required for certificates granted during 1979 and 1980. The proposed transition rule would divide certificates into two groups: those granted under the prior twelve-month rule and existing thresholds for a time period extending into 1980; and those granted during 1979 under the proposed calendar-year rule and new thresholds. The transition rule would provide a mechanism whereby all budget-type certificates for gas supply facilities would be on a calendar-year basis by January 1, 1981.

With respect to the first category (certificates granted during 1979 under the prior twelve-month rule for a period extending into 1980), application for new certificates should be made at least two months before the termination of existing certificates. If such application is made it would be for a time period extending to December 31, 1980. The budget thresholds for total project costs for such applications are to be pro-rated among the number of months to be covered by the desired certificate. For example, a company holding a budget-type certificate granted in 1979 for a period ending July 1, 1980 may apply for a certificate whose time period will run July 1, 1980 through December 31, 1980. The applicable budget thresholds for such an application would be one-half of those stipulated by § 157.7(b)(1)(i) of the proposed Regulations for a full calendar-year certificate.

The second category, applications for budget-type construction certificates made during 1979 but after the thresholds proposed by this Notice (or some other thresholds reflective of this Notice) go into effect will be handled differently. Such applications, irrespective of the commencement date sought, would be made for a period extending to December 31, 1980. As with the first category, applications would have to be made at least two months prior to the termination of the existing certificate and the budget thresholds for total project cost would be pro-rated. For example, if application is made for a certificate to commence October 1, 1979, that certificate would be made to cover the 15 months, October 1, 1979 through

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December 31, 1980. The total project cost limitations applicable to such an application would be one and one-quarter of those provided for under § 157.7(b)(1)(i) of the proposed Regulations.

Only the total project thresholds of § 157.7(b)(1)(i) would be pro-rated under the proposed transition rules. The single project limitations of § 157.7(b)(1)(ii) would remain the same for any application. This reflects the view that for purposes of the transition period, single project certificates are less amenable to pro-ration than total project certificates. In addition, maintaining the single project limitations, at least with respect to certificates which may be granted for more than a twelve-month period, will provide some limitations upon the scope of the certificates.

No provision has been made in the transition rules to permit those holding budget certificates at the time the proposed changes go into effect to amend those certificates so as to conform them to an expanded definition of "gas-supply" facilities. This expresses the Commission's view that, for purposes of budget applications granted under § 157.7(b), the applicable definition of the facilities involved should remain the one under which the application was made and the certificate was granted.

Section 2.58 of the Commission's General Policy and Interpretations contains language which is similar to, and duplicative of, that contained in § 157.7(b). Therefore, it is proposed that this section should be deleted.

Finally, it is proposed that these proposed revisions would become effective 30 days from the date of promulgation of final regulations.

While comments are invited on all facets of this proposal, comments are specifically invited on: (1) The advisability of increasing the total budget limit by increasing the total project cost limits and increasing the 2 percent limitation to 3 percent; (2) increasing the single project cost limits; (3) increasing the limits for pipeline companies with small plant investments; (4) changing the definition of gas purchase facilities; and (5) proposing that all gas-purchase budgets be authorized on a calendar-year basis. In addition, comments are also requested as to the information required under the provisions of § 157.7(b)(3) for construction completion reports.

Public Comment Procedures

Interested persons may participate in this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before May 25, 1979. Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79–37), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written submittals will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during regular business hours. The Commission will consider all written submittals before acting on the proposed amendments and the proposals contained in this notice may be changed in the light of submissions received.

(Natural Gas Act, as amended, 15 USC 717f and 717o, Department of Energy Organization Act, Pub. L. No. 95–91, 42 USC 7172, Exec. Order No. 12009, 42 **Fed. Reg.** 46267.)

In consideration of the foregoing, it is proposed to amend Parts 2 and 157 of Title 18 Code of Federal Regulations as set forth below.

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

1. Part 2 is amended by deleting § 2.58 in its entirety.

2. Section 157.7 is amended in paragraph (b) by revising the title, revising the introductory paragraph, revising subparagraphs (1), (3), and (4) and by adding subparagraphs (5), (6), and (7) to read as follows:

§ 157.7 Abbreviated applications.

* * * * *

(b) *Gas-supply facilities—budget-type applications.* An abbreviated application requesting a budget-type certificate authorizing the construction of gas-supply facilities during a given calendar-year period and operation thereafter may be filed when:

(1)(i) The total estimated cost of the gas-supply facilities proposed in the application does not exceed 3 percent of the applicant's gas plant (Account 101, Uniform System of Accounts Prescribed for Natural Gas Companies) or $20 million, whichever is the lesser, except that an applicant with less than $16⅔ million in such gas plant account may have a total gas-supply facility budget amount of $500,000.

(ii) The cost of gas-supply facilities for any single project to be installed during the authorized construction period does not exceed 25 percent of the total budget amount or $2.5 million, whichever is the lesser, except that a single offshore project, including any in the disputed zone, is limited to $3.5 milion, or the total budget amount, whichever is the lesser; provided, further, that the 25 percent single project cost limit shall not be applicable to those companies limited to a total budget of $500,000 as provided in clause (i) of this subparagraph.

* * * * *

(3) The applicant agrees to file with the Commission by the earlier of March 1 of the year following the calendar year for which authorization was granted, or within 60 days after the expiration of the authorized construction period, a statement containing for each individual project constructed under the budget authorization:

(i) a description of the gas-supply facilities installed, *e.g.*, miles and size of pipelines, compressor horsepower, metering facilities;

(ii) the location of gas-supply facilities installed;

(iii) the actual installed cost of gas-supply facilities subdivided by size of pipelines, compressor horsepower, metering facilities and appurtenant facilities;

(iv) the estimated recoverable gas reserves in MCF at 14.73 psia made available to the applicant by means of the facilities last installed;

(v) the names of the fields connected; and

(vi) the location, including well number, of the facility attached if the attachment is for gas owned or produced by the applicant, or if the attachment is for gas purchased by the applicant, the names of the independent producers or other sellers from whom the gas is being purchased, together with the respective dates of their gas sales contracts, and FERC gas rate schedule designations, if applicable.

(4) For purposes of this paragraph, "gas-supply facilities" means those facilities, subject to the jurisdiction of the Commission under the Natural Gas Act which are:

(i) necessary to connect the facilities of an independent producer or other similar seller, with the system of the gas purchaser or the system of another natural gas company authorized to transport such gas for the account of, or for the exchange of such gas with, the gas purchaser; or

(ii) necessary to attach gas supplies in which a pipeline company has an ownership interest, whether company-developed and produced, acquired in place, or developed in conjunction with others, with the system of the pipeline company or the system of another natural gas company authorized to transport such gas for the account of, or for the exchange of such gas with, said pipeline company.

(5) Except as provided in subparagraph (b)(6) of this paragraph, applications made pursuant to this paragraph shall be filed with the Commission no later than October 1 of the year preceding the calendar year for which authorization is sought.

(6) *Transitional rules.* (i) In the event that a particular certificate granted under this paragraph prior to [date instant proposed rulemaking goes into effect] lapses during calendar year 1980, any subsequent certificate applied for prior to October 1, 1980 shall be for a period extending to December 31, 1980;

(ii) In the event that a particular certificate granted under this paragraph prior to [date instant proposed rulemaking goes into effect] lapses during calendar year 1979, any subsequent certificate applied for prior to October 1, 1980 shall be for a period extending to December 31, 1980.

(iii) Certificates granted pursuant to either subparagraphs (b)(6)(i) or (ii) of this paragraph shall be made at least 60 days before the prior certificate lapses and shall be pro-rated with regard to the applicable thresholds of subparagraph (b)(1)(i) of this paragraph to the number of months such certificate is to be in effect.

(7) *Filing.* Budget-type applications to construct and operate "gas-supply facilities" may be filed by either or both the gas-purchaser/owner and another natural gas company authorized to transport gas for the account of, or for the exchange of gas with, the gas-purchaser/owner, depending upon which company or companies will actually construct and operate the budget-type facilities.

[Docket No. RM 79-37]

¶ 32,020A Discontinuation of the Use of Certain FERC Forms

44 F. R. 24577 (April 26, 1979).

[18 CFR Parts 2, 3, 4, 141, and 260]

Discontinuation of the Use of Certain FERC Forms

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to discontinue the use of data collection forms no longer needed by the Commission for its regulatory functions. The proposal is part of a continuing Commission effort to re-evaluate data collection by the Commission, and limit its data requirements to the minimum amount of information required to discharge its regulatory responsibilities.

DATE: Written comments by May 25, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (Reference Docket No. RM79–38).

FOR FURTHER INFORMATION CONTACT: Ronald D. Storey, Office of the Executive Director, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 9200, Washington, D.C. 20426, (202) 275–4111 or Teresa Ponder, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 8100–J, Washington, D.C. 20426, (202) 275–4236.

SUPPLEMENTARY INFORMATION: Notice is hereby given that the Federal Energy Regulatory Commission (Commission) proposes to amend §§ 2.10, 2.11(c), 2.11(d), 3.142(a), 3.170(a), 4.1, 4.2, 4.3, 4.6, 4.7, 4.10, 4.14, 4.20, 4.25, 141.7, 141.11, 141.12, 141.13, 141.26, 141.60, 141.300, 260.20, and 260.21 of Title 18 of the Code of Federal Regulations to discontinue the use of data collection forms no longer needed by the Commission for its regulatory functions.

Background

The Commission has initiated this rulemaking in accordance with the policy set forth in President Carter's Executive Order No. 12044 (Order) entitled "Improving Government Regulations." [1] The Order generally requires federal agencies, not including independent regulatory agencies, to evaluate and, where necessary, to improve their regulations in order to, among other things, minimize "compliance costs, paperwork, and other burdens on the public." Although this Commission is not required to comply with the Order, it has chosen to comply with the President's request that independent regulatory agencies voluntarily apply the policies and procedures enunciated in the Order.

This rulemaking is part of an ongoing effort to eliminate unnecessary burdens on the industries regulated by the Commission. All data elements contained in forms submitted to the Commission are being evaluated to determine how many of the data are needed by the Commission to carry out its regulatory functions. Forms which do not produce information needed by the Commission will be eliminated as FERC forms.

Some of the forms which the Commission proposes to discontinue were originally promulgated under authority granted to the Federal Power Commission (FPC) by sections 202(a) and 311 of the Federal Power Act (FPA) (49 Stat. 863; 16 U.S.C. 791(a)). Section 202(a) deals with the division of the country into regional districts for the voluntary interconnection and coordination of electric facilities.[2]

[1] 43 FR 12661, March 24, 1978.

[2] The Commission still has the authority under section 202(b) to order interconnections when necessary or appropriate in the public interest.

Section 311 authorizes investigations and information gathering relating to electric energy. These functions, among others, were transferred to the Secretary of Energy (Secretary) by section 301(b) of the Department of Energy Organization Act [3] (DOE Act) (Pub. L. No. 95-91, 91 Stat. 565). The authority to administer these functions was in turn delegated by the Secretary to the Energy Information Administration (EIA) [4], the Economic Regulatory Administration (ERA) [5], and the Commission.[6] The Secretary gave FRA the authority to administer section 202(a) of the FPA, and gave EIA the authority to administer section 311 of the FPA. The Commission was also given the authority to carry out the functions under section 311 to the extent needed to perform its other vested or delegated functions.

These changes in the Commission's regulatory responsibilities coupled with a desire to reduce the reporting burden on industry to require only those data necessary to the discharge of those responsibilities, permit us to propose that several forms be discontinued. While the Commission proposes to discontinue the requirement that these data be reported, the public should be aware that EIA or ERA may determine that collection of some of the data elements is necessary to the proper discharge of their respective statutory responsibilities. The effective date of a final rule issued by the Commission discontinuing collection of any forms listed herein will be such that EIA, ERA, or any other Federal agency will have sufficient time to justify the need for and receive OMB approval of collection of such data under that agency's own authority.

The evaluation of the Commission's forms has involved extensive staff review. Forms were inventoried and identified by the staff as necessary or unnecessary for the fulfillment of the Commission's regulatory responsibilities.

The forms which the Commission proposes to discontinue were determined to be unnecessary to the fulfillment of the Commission's regulatory functions.

Forms To Be Discontinued

The Commission considers the following forms unnecessary and proposes to discontinue their collection:

Form No.	Title as shown in C.F.R.	18 C.F.R. §§
6	Initial Cost Statement for Licensed Projects	141.11, 3.142(a)(23).
7	Statement of Actual Legitimate Original Cost of Construction	141.12, 3.142(a)(24).
9	Annual Report for Licensees of Privately Owned Major Projects (Utility and Industrial).	141.13, 3.142(a)(25).
17	Monthly Report of Natural Gas Pipeline Curtailments	None.
23B	Quarterly Electric Utility Generation and Fuel Planning Report (Expired 8-31-78).	141.300.
38	No C.F.R. title. Title of form: Electric Generating Station and Substation Data and Location.	3.142(a)(42) (None—internal use only).
45	Report of New Non-Jurisdictional Sales of Natural Gas	260.20, 3.170(a)(30).
64	Natural Gas Companies, Annual Report of Producer Expenditures, Exploration and Development Activity, Production, Reserve Additions, and Revenues (Expired 12-31-78).	260.21, 3.170(a)(27).
37A	Weekly Fuel Emergency Report, Revised (Coal)	141.60, 3.142(a)(45).
237B	Weekly Fuel Emergency Report, Revised (Oil)	141.60, 3.142(a)(45).
ICC, ARC-41	No C.F.R. title. Title of form: Report of Expenditures for Additions and Betterment—Oil Pipeline Companies.	(None—internal use only).

[3] Section 301(b) provides, generally, that powers given the FPC under the FPA and the Natural Gas Act (15 U.S.C. 717) which were not transferred to the Commission by Title IV of the DOE Act are vested in the Secretary.

[4] Delegation Order No. 0204-3, October 1, 1977, 42 FR ——.

[5] Delegation Order No. 0204-4, October 1, 1977, 42 FR ——.

[6] Delegation Order No. 0204-1, October 1, 1977, 42 FR 55837.

It should be noted that Form Nos. 6, 7, and 9 contained in the above table are presently filed by licensed projects in accordance with section 4(b) of the FPA.[7] The Commission feels that the proposed amendments to Part 4 of the regulations, which eliminate the requirements for filing these forms with the Commission, will, nevertheless, meet the requirements of section 4(b) of the FPA. Under the current and proposed regulations, the actual legitimate original cost of and the net investment in the project is determined by the Commission after an audit conducted by its representatives. The proposed regulations require the licensed project, prior to the audit, to file a letter instead of the forms stating that all the information needed for the Commission's determination is contained in the project's books of account and is recorded in compliance with the Commission's Uniform System of Accounts.

The Commission also proposes to discontinue collection of the following forms. It should be noted, however, that some or all of the information reported on these forms may be collected by the EIA in carrying out its information gathering functions.

Form No.	Title as shown in C.F.R.	18 C.F.R. §§
1M	Annual Report for Municipal Electric Utilities Having Annual Electric Operating Revenues of $250,000 or More	141.7, 3.142(a)(22)
13	Summary for National Electric Rate Book	141.26, 3.142(a)(32)

Finally, information reported on the following forms may be needed by the ERA but would no longer be collected by the Commission under this proposal.

Form No.	Title as shown in C.F.R.	18 C.F.R. §§
Unnumbered (GAO authorization No. RO309)	Untitled. Information reported: Reliability and adequacy of electric services—report by regional councils on coordinated regional bulk power supply programs.	2.11(c), (d)
Unnumbered (GAO authorization No. RO327)	Untitled. Information reported: Actions for minimizing the consequences of bulk power supply interruptions or shortages—report on contingency plans for operating in emergency situations and for possible load reductions or curtailment.	2.10(b)

The Commission invites written comments relevant to this proposal. Because the information received through these comments will be shared by the Commission and the EIA, any comments should separate the issues addressed according to the following categories:

1. Whether the data in question serve any Commission regulatory function;

2. If they do not, whether there is, nevertheless any reason for continued collection of the data by another federal agency;

3. Whether State Commissions have a regulatory need for any of the data; and

4. Whether the discontinuation of the use of Form Nos. 6, 7, and 9 and the related changes to Part 4 of the regulations satisfy the requirements of section 4(b) of the FPA.

The Commission has already allowed Form Nos. 23B and 64 expire, and respondents to this proposed rulemaking

[7] Section 4(b) of the FPA provides, in part, that the Commission is authorized and empowered:

(b) To determine the actual legitimate original cost of and the net investment in a licensed project, and to aid the Commission in such determinations, each licensee shall, upon oath, within a reasonable period of time to be fixed by the Commission, after the construction of the original project or any addition thereto or betterment thereof, file with the Commission, in such detail as the Commission may require, a statement in duplicate showing the actual legitimate original cost of construction of such project, addition, or betterment, and of the price paid for water rights, rights-of-ways, lands, or interest in lands.

should address comments to only those forms currently filed with the Commission and specifically enumerated in this proposal. Anyone suggesting the continued collection of data which are contained in the forms we propose to eliminate and which are no longer needed by the Commission, should identify who can use the data, and for what purpose.

Public Comment Procedure

Interested persons may participate in this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before May 25, 1979. Each person submitting a comment should include his or her name and address, identify the notice (Docket No. RM79), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission.

Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

(Natural Gas Act, *as amended*, 15 U.S.C. 717; Federal Power Act, 16 U.S.C. 791(a); Administrative Procedure Act, 5 U.S.C. 553; Department of Energy Organization Act, Pub. L. No. 95-91; E.O. 12009, 42 FR 46267; Delegation Order No. 0204-1, 42 FR 55638.)

In consideration of the foregoing, it is proposed to:

1. Discontinue use of FPC Form No. 38, entitled Electric Generating Station and Substation Data and Location;

2. Discontinue use of Form No. ICC-ACR-41, entitled Expenditures for Additions and Betterments;

3. Discontinue use of FPC Form No. 17, entitled Monthly Report of Natural Gas Pipeline Curtailments; and

4. Amend Parts 2, 3, 4, 141, and 260 of Chapter I, Title 18 Code of Federal Regulations, as set forth below.

By direction of the Commission.

Lois D. Cashell,
Acting Secretary.

PART 2—GENERAL POLICY AND INTERPRETATIONS

§ 2.10 [Amended]

1. Section 2.10 is amended by deleting paragraph (b) in its entirety and deleting the words "(a) *Actions.*" from paragraph (a).

§ 2.11 [Amended]

2. Section 2.11 is amended by deleting paragraphs (c) and (d) in their entirety.

PART 3—ORGANIZATION OPERATION; INFORMATION AND REQUESTS

§ 3.142 [Amended]

3. Section 3.142 is amended in paragraph (a) by deleting subparagraphs (22), (23), (24), (25), (32), (42), and (45) in their entirety and redesignating subparagraphs (26) as (22); (27) as (23); (28) as (24); (29) as (25); (30) as (26); (31) as (27); (33) as (28); (34) as (29); (35) as (30); (36) as (31); (37) as (32); (38) as (33); (39) as (34); (40) as (35); (41) as (36); (43) as (37); (44) as (38); (46) as (39); (47) as (40); and (48) as (41).

§ 3.170 [Amended]

4. Section 3.170 is amended in paragraph (a) by deleting subparagraphs (27) and (30) in their entirety and redesignating subparagraphs (28) as (27); (29) as (28); and (31) as (29).

PART 4—LICENSES, PERMITS, AND DETERMINATION OF PROJECT COSTS

5. Section 4.1 is amended to read as follows:

§ 4.1 Initial cost statement.

When a project is constructed under a license issued under the act, the licensee shall, within one year after the original

project is ready for service, file with the Commission a letter, in quadruplicate, declaring that the original costs have been booked in compliance with the Commission's Uniform System of Accounts and that the books of accounts are ready for audit. The licensee's books of accounts for each project shall be maintained in such a fashion that each year's additions, betterments, and deletions to the project may be readily ascertained. Duplicates of the information made available in accordance with this section must be released for public use when specifically requested. Complying with the provisions of this section (§ 4.1), satisfies the filing requirements of section 4(b) of the Federal Power Act (16 U.S.C. 797(b)).

§ 4.2 [Removed]

6. Section 4.2 is deleted in its entirely.

§ 4.3 [Redesignated as § 4.2]

7. Section 4.3 is redesignated as § 4.2 and is amended to read as follows:

§ 4.2 Report on project cost.

When the original cost declaration letter, filed in accordance with § 4.1, is received by the Commission, its representative will schedule and conduct an audit of the accounts and examine and analyze the books, cost records, engineering reports, and other records supporting the project's original cost. The cost records shall be supported by memorandum accounts reflecting the indirect and overhead costs prior to their spread to primary accounts as well as all the details of allocations including formulas utilized to spread the indirect and overhead cost to primary accounts. The audit may include an inspection of the project works. Upon completion of the audit, a report will be prepared for the Commission setting forth the audit findings and recommendations with respect to the cost as claimed.

§ 4.4 [Redesignated as § 4.3; § 4.5 Redesignated as § 4.4]

8. Section 4.4 is redesignated as § 4.3 and § 4.5 is redesignated as § 4.4.

§ 4.6 [Redesignated as § 4.5]

9. Section 4.6 is redesignated as § 4.5 and is amended to read as follows:

§ 4.5 Burden of proof.

The burden of proof to sustain each item of claimed cost shall be upon the licensee and only such items as are in the opinion of the Commission supported by satisfactory proof may be entered in the electric plant accounts of the licensee.

§4.7 [Redesignated as § 4.6]

10. Section 4.7 is redesignated as § 4.6 and is amended to read as follows.

§4.6 Findings.

Finding action by the Commission will be in the form of a finding and order entered upon its minutes and served upon all parties to the proceeding. One copy of the order will be furnished to the Secretary of Treasury by the Commission. The licensee's books of account for the project shall be adjusted to conform to the actual legitimate cost as revised by the order of the Commission. These adjustments and the project may be audited by Commission representatives, as scheduled.

11. Section 4.10 is revised to read as follows:

§4.10 Valuation data.

In every case arising under section 23(a) of the act requiring the determination of fair value of a project already constructed, the licensee shall, within six months after the date of issuance of a license, file with the Commission a letter, in quadruplicate, containing a statement to the effect that an inventory and appraisal in detail, as of the effective date of the license, of all property subject thereto and to be so valued has been completed. The letter shall also include a statement to the effect that actual legitimate original cost, or if not known, the estimated original cost of the property, by prescribed structural and functional items and units, and an estimate of accrued depreciation segregated as to each separate major item or unit of

property have been established and classified as prescribed in the Commission's Uniform System of Accounts. The licensee's books of account for each project shall be maintained in such a fashion that each year's additions, betterments, and deletions to the projects may be readily ascertained. Duplicates of the information made available in accordance with this section must be released for public use when specifically requested.

12. Section 4.14 is revised to read as follows:

§4.14 Hearing upon report.

After the expiration of the time within which a protest may be filed, a public hearing will be ordered in accordance with § 1.20 of this chapter. The Commission after the conclusion of the hearing will make a finding of fair value, accompanied by an order which will be served upon the licensee and all parties to the proceeding. One copy of the order shall be furnished to the Secretary of the Treasury by the Commission. The licensee's books of account for the project shall be adjusted to conform to the fair value of the project as revised by the order of the Commission. These adjustments and the project may be audited by Commission representatives, as scheduled.

13. Section 4.20 is revised to read as follows:

§4.20 Initial statement.

In all cases where licenses are issued for projects already constructed, but which are not subject to the provisions of section 23(a) of the act (49 Stat. 846; 16 U.S.C. 816), the licensee shall, within 6 months after the date of issuance of license, file with the Commission a letter, in quadruplicate, containing a statement to the effect that an inventory in detail of all property included under the license, as of the effective date of such license, has been completed. The letter shall also include a statement to the effect that actual legitimate original cost, or if not known, the estimated original cost of the property, by prescribed structural and functional items and units, and an estimate of the accrued depreciation segregated as to each separate major item or unit of property have been established and classified as prescribed in the Commission's Uniform System of Accounts. The licensee's books of account for each project shall be maintained in such a fashion that each year's additions, betterments, and deletions to the project may be readily ascertained. Duplicates of the information made available in accordance with this section must be released when specifically requested. Complying with the provisions of this section (§ 4.20) satisfies the filing requirements of section 4(b) of the Federal Power Act (16 U.S.C. 797(b)).

14. Section 4.25 is revised to read as follows:

§4.25 Findings

Final action by the Commission will be in the form of a finding and order entered upon its minutes and served upon all parties to the proceeding. One copy of the order shall be furnished to the Secretary of Treasury by the Commission. The licensee's books of account for the project shall be adjusted to conform to the actual legitimate cost as revised by the order of the Commission. These adjustments and the project may be audited by Commission representatives, as scheduled.

PART 141—STATEMENTS AND REPORTS (SCHEDULES)

§ 141.7 [Removed]

15. Section 141.7 is deleted in its entirety.

§ 141.11 [Removed]

16. Section 141.11 is deleted in its entirety.

§ 141.12 [Removed]

17. Section 141.12 is deleted in its entirety.

§ 141.13 [Removed]

18. Section 141.13 is deleted in its entirety.

§ 141.26 [Removed]

19. Section 141.26 is deleted in its entirety.

§ 141.60 [Removed]

20. Section 141.60 is deleted in its entirety.

§ 141.300 [Removed]

21. Section 141.300 is deleted in its entirety.

PART 260—STATEMENT AND REPORTS (SCHEDULES)

§ 260.20 [Removed]

22. Section 260.20 is deleted in its entirety.

§ 260.21 [Removed]

23. Section 260.21 is deleted in its entirety.

[The next page is 32,247-11.]

¶ 32,020B Exemption of Small Conduit Hydroelectric Facilities From Part I of the Federal Power Act

44 F. R. 24580 (April 26, 1979).

[18 CFR Part 4]

Exemption of Small Conduit Hydroelectric Facilities From Part I of the Federal Power Act

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission gives notice that it proposes to adopt regulations providing procedures for granting exemptions from regulation under Part I of the Federal Power Act, including the licensing of facilities, to conduit hydroelectric facilities having no more than 15 megawatts of installed capacity. The regulations are proposed under section 213 of the Public Utilities Regulatory Policies Act of 1978 which created a new section 30 of the Federal Power Act and granted the Commission discretion to determine the extent of exemptions from regulation.

DATE: Written comments by June 1, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, reference Docket No. RM79–35.

FOR FURTHER INFORMATION CONTACT:
Ronald Corso, Office of Electric Power Regulation, Federal Energy Regulatory Commission, Room 4400, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275–4863, or
Howard Jack, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8608, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275–4289.

SUPPLEMENTARY INFORMATION:

The Federal Energy Regulatory Commission (Commission) gives notice that it proposes to adopt regulations providing procedures for exemption of conduit hydroelectric facilities from regulation under Part I of the Federal Power Act.

Background

Section 213 of the Public Utility Regulatory Policies Act of 1978 (PURPA) amended the Federal Power Act (Act) by creating a new section 30 of the Act. Section 30 gives the Commission discretion to grant to certain facilities exemptions from the requirements of Part I of the Act. Such exemptions may be in whole or in part and may include exemption from Commission licensing. The facilities which may be exempted under section 30 must be located on non-federal lands and utilize only a man-made conduit operated primarily for distribution of water rather than generation of electricity. No facilities with an installed capacity greater than 15 megawatts are eligible for exemption.

The proposed rules establish procedures under which case-by-case determinations can be made on whether, and the extent to which, a particular facility under particular site conditions warrants exemption. Contents of an application for exemption are desinged to require the minimum information necessary to support an informed decision. In order to minimize necessary filings, exemption application requirements are in lieu of those that would be required for a license application. If an exemption from licensing is denied, the exemption application will be treated as the basis for an application for license. (Additional information not contained in the exemption application, however, may be required to complete the application as one seeking a license.) In addition, to minimize and simplify any burden on exemption applicants, these requirements are substantially less than those for the short-form license (minor) adopted in our recent rulemaking (Docket No. RM78–9) which covers

projects up to only 1.5 megawatts.[1] The proposed rules, moreover, apply these reduced application requirements to facilities up to 15 megawatts.

These proposed regulations have also been drafted with reference to the proposed regulations for general procedures for license and preliminary permit applications under Part I of the Act (Docket No. RM79–23). Those proposed regulations were promulgated by notice issued March 5, 1979, [44 FR 12432 (March 7, 1979)]. By reference to paragraphs (c) through (g) of proposed § 4.31 in that docket, the regulations proposed here would treat filings of exemption applications in the same manner as filings of preliminary permit or license applications with respect to accepting, rejecting, or curing deficiencies in the filing, requirements for additional information, and pre-application advice from the Commission staff.

The Commission believes that in many instances grant or denial of a small conduit hydroelectric facility exemption will be straightforward. Normally, it should be possible to review the merits of an application which meets the filing requirements of these new sections within 90 days and determine whether to grant or deny exemption. Accordingly, the proposed regulations provide for an automatic exemption, with certain standard terms and conditions, if the Commission has not specifically acted within that time. Where a particular application warrants, the Commission may act specifically within the 90 days to grant an exemption on special terms and conditions or to deny exemption. In extraordinary circumstances requiring additional time for information gathering or lengthier proceedings or deliberations (for instance, if an evidentiary hearing were ordered), the Commission may suspend the 90-day period. These provisions should assure expeditious action on exemption applications. The proposed regulations also provide the limited standard terms and conditions that would be included in any grant of exemption, even an automatic one.

As noted earlier, the proposed regulations take a case-by-case approach to exemption. The Commission and its staff have also considered the possibility of establishing generic exemptions by rule. There appear to be several difficulties with that approach, however. First, many important factual variables for any particular site and facility might affect whether and to what extent a facility should be exempted, as well as the proper terms and conditions for exemption. Second, there are many different possible combinations of the provisions of the Act that might appropriately by waived depending on the particular characteristics of various facilities and sites. Third, the consultation with fish and wildlife agencies required by section 30 appears to be facility-specific. For these reasons, the proposed regulations do not include generic exemptions. To gather additional views on these questions, however, the Commission invites persons interested in this rulemaking to comment on the efficacy of providing generic, rather than or in addition to facility-specific exemptions.

Three applications for exemption of the kind addressed by this proposed rulemaking have been filed with the Commission. Upon receipt of information sufficient to satisfy the application requirements in the proposed regulations, the Commission will proceed to consider those applications on an *ad hoc* basis under the authority of section 30 of the Federal Power Act. Although the 90-day automatic exemption provision in the proposed regulations would not apply, the Commission hopes to act on such an application within 90 days after the applicant is notified of acceptance for

[1] For example, mapping requirements for an exemption application are less stringent than those for a minor license application.

filing. Other applications that may be filed before final regulations are promulgated would also be considered on the same basis. Applicants who file acceptable applications for exemption before final regulations are adopted will not be required to refile in accordance with those regulations.

Summary of Proposed Regulations

Paragraph 4.65(a) explains that exemptions for small conduit hydroelectric facilities would be available for either constructed or unconstructed facilities that would otherwise need a license under Part I of the Act. Subparagraph 4.65(b)(4) defines "small conduit hydroelectric facilities" in terms similar to those in section 30 of the Act, with some clarifying details. Interested persons are invited to comment on whether the scope of the definition should be narrower or broader than that provided in this section.

Paragraph 4.66(a) provides that any person may apply for the exemption of a qualified facility from Part I of the Act. Paragraph (b) requires that an exemption application conform to various existing procedural requirements. An application must also provide certain specific information about the facility, to be contained in an initial statement, Exhibits A, B, and L, and an environmental report, as described in paragraph (b) of § 4.66. Among other things, Exhibit A must include a general location map; the recommendations which the applicant has obtained from the U.S. Fish and Wildlife Service, the National Marine Fisheries Service (in instances where anadromous fish may be involved), and any state agency regulating fish or wildlife resources; the applicant's comments on such recommendations; and other information considered relevant by the applicant. Exhibit B must include a description of the facility. An Exhibit L and an environmental report similar to those required for a minor project must also be filed. The Commission reemphasizes that these proposed exemption application regulations do not impose any additional filing requirements. Instead, they call for information in lieu of, and in simpler form than, that required for the license applications that would otherwise have to be filed.

Section 4.67 sets forth the avenues open to the Commission in processing applications for exemption. Under paragraph (a), the Commission would generally follow the same procedures articulated in paragraphs (c) through (g) of proposed § 4.31 for license and preliminary permit applications.[3] Notice of an exemption application would be published once in the county where the project is located. In paragraph (b) the Commission retains discretion to order a hearing on an application and to limit the issues to be considered there.

Paragraph (c) of § 4.67 automatically grants an exemption if the Commission does not take action within 90 days after the applicant is notified that its application is accepted for filing. In the alternative, the Commission may take action within that period to grant or deny the application explicitly under paragraph (d). That paragraph also provides for suspension of the 90-day action requirement in extraordinary circumstances.

Paragraph (f) of § 4.67 elaborates the standard terms and conditions for all exemptions. They include: Compliance with rules and orders to protect life, health, or property; the Commission's rights of investigation and enforcement; and compliance with the terms and conditions recommended by state and federal fish and wildlife agencies. In paragraph (g) the Commission also reserves the right to impose other conditions to protect water supply for consumption, the environment, public safety, and the water power resources of the region. Finally, under paragraph (h), interested agencies will be notified of the application for exemption and have 45 days to comment. Because of the relatively short period for comment and

[3] Docket No. RM79-23, *supra* p. 3.

Commission consideration, fish and wildlife agencies will also receive copies of the application. Any agency that does not comment within the 45 days will be presumed to have no objection to the exemption.

Written Comment Procedures

The Commission invites interested persons to submit written comments on the matters proposed in this notice. An original and 14 conformed copies of such comments must be filed with the Commission by June 1, 1979. Comments should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. All comments should refer to Docket No. RM79-35.

Written comments will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426. The Commission will consider all timely comments before acting on the matters in this notice.

(Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.* Public Utilities Regulatory Policies Act, Pub. L. No. 95-617, 92 Stat. 3117 *et seq.*; Executive Order No. 12009, 42 FR 46267.)

In consideration of the foregoing, the Commission proposes to amend Part 4 of Subchapter B, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Lois D. Cashell,
Acting Secretary.

1. Part 4 of Subchapter B, Chapter I, of Title 18 of the Code of Federal Regulations is amended by adding after § 4.60 the following sections 4.65, 4.66, and 4.67 to read:

Application for Exemption for Small Conduit Hydroelectric Facility

§ 4.65 Applicability and purpose.

(a) The provisions of these sections apply to applications for exemption of constructed or unconstructed small conduit hydroelectric facilities from all or part of the requirements of Part I of the Federal Power Act (including licensing) and of the regulations issued under Part I.

(b) *Definitions.* For the purposes of these sections:

(1) "Conduit" means any tunnel, canal, pipeline, aqueduct, flume, or similar man-made water conveyance which is operated for the distribution of water for agricultural, municipal, or industrial consumption, and not primarily for the generation of electricity.

(2) "Construction of a dam" means any construction, repair, reconstruction, or modification of a dam that either creates a new impoundment or increases the normal maximum surface elevation or the normal maximum surface area of an existing impoundment.

(3) "Dam" means any structure for impounding water.

(4) "Exempted facility" means a small conduit hydroelectric facility which has been granted an exemption under § 4.67.

(5) "Fish and wildlife agencies" means the U.S. Fish and Wildlife Service, the National Marine Fisheries Service (in any instance where anadromous fish may be affected), and any state agency exercising administration over fish or wildlife resources of the state in which a particular small conduit hydroelectric facility will be located.

(6) "Impoundment" means any body of water that a dam impounds.

(7) "Small conduit hydroelectric facility" means a facility, including all structures, fixtures, equipment, and lands used and useful in the facility's operation or maintenance, that is constructed, operated, or maintained for the generation of electric power and that:

(i) Utilizes for electric power generation the hydroelectric potential of a conduit;

(ii) Is not located, in whole or in part, on any of the public lands or reservations of the United States;

(iii) Has an installed generating capacity of 15 megawatts or less;

(iv) Does not rely, in whole or in significant part, upon a dam for its structural support or stability;

(v) Does not rely upon construction of a dam for any portion of the hydrostatic head that the facility uses for power generation; and

(vi) Releases the water it uses for power generation back to a conduit after power generation.

§ 4.86 Application for exemption.

(a) Any citizen, association of citizens, domestic corporation, municipality, or state may apply for an exemption for a small conduit hydroelectric facility from all or part of the provisions of Part I of the Federal Power Act (including any licensing requirements) and the regulations issued under Part I.

(b) Except as otherwise prescribed in this part, an application for exemption for a constructed or unconstructed small conduit hydroelectric facility must conform to the requirements set forth in §§ 1.5, 1.14, 1.15, 1.16, and 1.17 of this chapter. An application must also include an initial statement, Exhibits A, B, and L, and an Environmental Report.

(1) An initial statement must be set forth as follows:

Before the Federal Energy Regulatory Commission

Application for Exemption for Small Conduit Hydroelectric Facility

[Name of applicant] applies to the Federal Energy Regulatory Commission for an exemption for the [name of facility] small conduit hydroelectric facility from certain provisions of Part I of the Federal Power Act.

The location of the facility is:

State or territory: ————

County: ————

Township or nearby town: ————

The exact name and business address of each applicant are:

_____

_____

_____

The exact name and business address of each person authorized to act as agent for the applicant in this application are:

_____

_____

_____

[Name of applicant] is a [citizen, association of citizens, domestic corporation, municipality, or state, as appropriate].

The provisions of Part I of the Federal Power Act for which exemption is requested are:

[List here all sections or subsections for which exemption is requested.]

(2) *Exhibit A* must contain:

(i) A brief description of the related conduit, the purposes for which it is used, and the purposes for which power from the small conduit hydroelectric facility will be used;

(ii) A statement of the sources of the water supply for the related conduit;

(iii) A general location map showing:

(A) The physical structures of the small conduit hydroelectric facility in relation to the conduit and any dam to which any of those structures may be attached.

(B) A proposed boundary for the facility, delineatd by indicating distances from the facility's structures,

(C) The centerline and width of right-of-way for any transmission line that will transmit power from the facility to the point of junction with a disribution system or an interconnected primary transmission system, and

(D) The ownership of the parcels of lands within the proposed boundary for the facility;

(iv) Documentary evidence that the applicant consulted with fish and wildlife agencies before filing, including any terms or conditions those agencies may determine are appropriate to prevent loss of, or damage to, fish or wildlife resources and to carry out the provisions of the Fish and Wildlife Coordination Act [16 U.S.C. 661 *et seq.*];

(v) The applicant's comments on any recommendations made under paragraph (b)(2)(iv) of this section;

(vi) A description of the nature and extent of any construction, reconstruction, repair, or other modification of any dam that would occur in association with construction of the proposed facility, including a statement of the normal maximum surface elevations and normal maximum surface areas of the impoundment for

that dam before and after that construction, reconstruction, modification, or repair; and

(vii) Any additional information the applicant considers important.

(3) *Exhibit B* must contain a facility description and proposed mode of operation (with appropriate references to Exhibits A and L), including, as appropriate: the number of generating units, including auxiliary units, the capacity of each unit, and provisions, if any, for future units; type of hydraulic turbine(s); description of how the plant is to be operated, manual or automatic, and whether the plant is to be used for peaking; estimated average annual generation in kilowatt-hours; estimated average head on the plant; estimated hydraulic capacity of the plant (flow through the plant) in cubic feet per second; estimated average flow of the conduit at the plant or point of diversion and the estimated average amount of that flow available for power generation; sizes, capacities, and construction materials, as appropriate, of pipelines, ditches, flumes, canals, intake facilities, powerhouses, transmission lines, and any other structures associated with the facility; estimated cost of the facility; and the planned date for beginning construction of the facility.

(4) *Exhibit L* must consist of a drawing of facility structures and equipment. It must be a simple ink drawing or a drawing of similar quality on a sheet *no smaller than* 8 inches by 10½ inches, drawn to a scale no smaller than one inch equals 50 feet for plans and profiles, and one inch equals 10 feet for sections. The drawing must show a plan, elevation, profile, and section of the power plant and any other principal facility structure and of any dam to which a facility structure would be attached. Generating and auxiliary equipment proposed must be clearly and simply depicted and described. The plan view must include a north arrow.

(5) The *Environmental Report* must contain information consistent with the scope and environmental impact of the proposed facility's construction and operation. The environmental report must set forth in a clear and concise manner:

(i) A description of the environmental setting in and near the facility area, including vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational use, socio-economic aspects, historical and archeological resources, and visual resources. Special attention must be given to endangered and threatened plant and animal species, critical habitats, and sites eligible for or included on the National Register of Historic Places. Assistance in the preparation of this information may be obtained from state natural resources departments and from local offices of federal natural resources agencies.

(ii) A description of the expected environmental impacts resulting from the continued operation of a constructed facility or from the construction and operation of an unconstructed facility. Include a discussion of specific measures proposed by the applicant and others to protect and enhance environmental resources and to mitigate adverse impacts of the facility on the environmental resources and values, the costs of those measures, and the party undertaking to implement those measures if other than the applicant.

(iii) A description of alternative means of obtaining an amount of power equivalent to that provided by the facility in the event that the facility were not constructed (or, if in the facility is already constructed, in the event that the facility's operation ceased).

(iv) A description of any steps taken by the applicant in consulting with federal, state, or local agencies during the preparation of the environmental report. Indicate any agencies that have received the final report and provide copies of any letters containing comments from those agencies.

(c) An applicant for exemption must submit to the Commission's Secretary for filing an original and 14 copies of the

application, including full-size prints of all required maps and drawings. The originals (microfilm) of maps and drawings are not to be filed with the initial application, but may be requested pursuant to paragraph (c) of § 4.31.

§ 4.67 Action on application for exemption.

(a) An application for exemption for a small conduit hydroelectric facility will be processed in accordance with paragraphs (c) through (g) of § 4.31 of this part, except that notice will be published only once in a daily or weekly newspaper of general circulation in any county in which the facility would be located. The additional time that may be allowed under paragraph (d) of § 4.31 for correcting deficiencies in an application for exemption may not exceed 45 days.

(b) The Commission may order a hearing on an application for exemption either on its own motion or the motion of any party in interest. Any such hearing shall be limited to the issues prescribed by order of the Commission.

(c) If the Commission has not taken one of the actions set forth in paragraph (d) of this section within 90 days after notifying the applicant that its application for exemption is accepted for filing, the application will be considered granted as requested.

(d) Within 90 days after notifying an applicant for exemption that its application is accepted for filing, the Commission may take any of these affirmative actions:

(1) Grant the exemption as requested;

(2) Grant an exemption from provisions of Part I of the Federal Power Act (and the regulations issued under those provisions) other than those for which exemption was requested, upon finding that modification of the exemption requested is necessary or desirable to carry out the purposes of Part I;

(3) Deny exemption, upon finding that exemption is inconsistent with the provisions of Part I of the Federal Power Act or is otherwise inconsistent with the public interest; or

(4) Suspend the 90-day period for action under paragraphs (d) (1) through (3) of this section upon finding that additional time is necessary for gathering additional information, conducting additional proceedings, or deliberating on the issues raised by the application for exemption.

(e) If exemption from licensing is denied, the application for exemption will be treated as the basis of an application for license. Additional information conforming with the requirements of the Commission's regulations for license applications may be required in order to complete an application for license.

(f) Any exemption granted under paragraph (c) or (d) of this section for a small conduit hydroelectric facility is subject to the following standard terms and conditions:

(1) *Article 1.* The construction, operation, and maintenance of the exempted facility must comply with any rule or order the Commission may from time to time prescribe for the protection of life, health, or property.

(2) *Article 2.* The Commission reserves the right to conduct investigations under sections 4(g), 306, 307, and 311 of the Federal Power Act with respect to any acts, complaints, facts, conditions, practices, or other matters related to the construction, operation, or maintenance of an exempted facility. If any term or condition of the exemption for an exempted facility is violated, the Commission may revoke the exemption, issue a suitable order under section 4(g) of the Federal Power Act, or take appropriate action for enforcement, forfeiture, or penalties under Part III of the Federal Power Act.

(3) *Article 3.* The construction, operation, and maintenance of the exempted facility must comply with any terms and conditions that fish and wildlife agencies may determine are appropriate to prevent loss of, or damage to, fish or wildlife resources or

otherwise to carry out the purposes of the Fish and Wildlife Coordination Act.

(g) The Commission may also prescribe additional terms or conditions in granting an exemption for a small conduit hydroelectric facility, in order to:

(1) Protect the quality or quantity of the related water supply for agricultural, municipal, or industrial consumption;

(2) Otherwise protect life, health, or property;

(3) Avoid or mitigate adverse environmental impact; or

(4) Conserve, develop, or utilize in the public interest the water power resources of the region.

(h) Notice of an application for exemption will be circulated to interested agencies at the time the applicant is notified that the application is accepted for filing. Fish and wildlife agencies will also receive copies of the application. If a particular agency does not comment within 45 days from the issuance of that notice, that agency will be presumed to have no objection to the exemption requested. A fish or wildlife agency that does not comment within that time will also be presumed to have no recommendations for terms or conditions of the exemption other than those that may be included in Exhibit A of the application for exemption.

¶ 32,021 Procedures for Evaluating the Economic Practicability and Reasonable Availability of Alternate Boiler Fuel for Large Boiler Facilities

44 F. R. 26894 (May 9, 1979).

Procedures for Evaluating the Economic Practicability and Reasonable Availability of Alternate Boiler Fuel for Large Boiler Facilities

AGENCY: Federal Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to establish a procedure for determining the economic practicability and reasonable availability of alternate fuel for essential agricultural use establishments which:

Have the capacity to use more than 300 Mcf of natural gas on a peak day;

Have actually used a fuel other than natural gas as a boiler fuel continuously for 60 days during the 1976–1978 period;

Have requested or intends to request that their natural gas for boiler fuel use be classified as Priority 2 Entitlement in the curtailment plan of their interstate pipeline supplies.

The purpose of the rule is to establish a procedure for determining the economic practicability and reasonable availability of alternate fuel for essential agricultural use establishments which use natural gas as boiler fuel and which seek Priority 2 Entitlements for that gas.

DATE: Written comments by May 30, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capital Street, NE., Washington, D.C. 20426 (Reference Docket No. RM79–40).

FOR FURTHER INFORMATION CONTACT: Mary Jane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 8000, Washington, D.C. 20426, (202) 275–4283.

Background

The Federal Energy Regulatory Commission (Commission) hereby gives notice of its intention to promulgate a rule relating to the procedure for evaluating alternative fuel availability for essential agricultural users which use natural gas in large boilers. Section 401(a) of the Natural Gas Policy Act of 1978 (NGPA), provides that, to the maximum extent practicable, curtailment of supplies to essential agricultural users is proscribed unless such supplies are needed to fulfill the needs of certain high-priority users. Section 401(b) of the NGPA provides, however, that curtailment of the natural gas used by essential agricultural users also may occur if they can use an alternate fuel that is economically practicable and reasonably available. The Commission, in this notice, is proposing procedures whereby the provisions of section 401(b) can be implemented, so that the Commission can determine if certain large boiler fuel users certified by the United States Department of Agriculture (USDA) have access to alternate fuel that is reasonably available and economically practicable.

The Commission believes that its authority pursuant to section 401 of the NGPA is discretionary and it proposes to focus its attention on determinations concerning alternative fuel which may be reasonably available and economically practicable to boiler fuel users using over 300 Mcf of gas per peak day. It has been the Commission's experience in administering natural gas curtailment policies since the early 1970's that it is often difficult to substitute other fuels in place of natural gas in process and feedstock applications. Small boilers usually have difficulty in utilizing fuels other than natural gas unless extensive conversion occurs. Moreover, Commission

experience suggests that the economics and logistics of utilizing other fuels in large boilers is often favorable when compared with natural gas. Taking these factors into consideration, as well as taking note of the substantial amount of boiler fuel actually or potentially covered by the proposed USDA volumetric certification rule, the Commission has decided that administrative efficiency of its 401 implementation responsibilities would be best served by concentrating on examination of the economics and logistics of large boiler fuel users.

In particular, the Commission will focus its examination on those boilers that have an alternative fuel capability which has been exercised for substantial periods during recent years. This is not intended to imply a legal assumption that such boilers have the type of economic and praticable capability specified in section 401. However, such boilers appear to be the facilities most likely to have cost and fuel supply conditions that would favor use of fuels other than natural gas. Conversely, facilities which would have to install new capabilities or facilities where only natural gas has been used during the last few years would, *a priori*, appear less likely to have economics and logistics that favor the use of fuels other than natural gas.

There are also technical considerations involved in selecting boilers that use in excess of 300 Mcf on a peak day. Boilers consume fuel in order to generate heat or electricity, while other users need natural gas because the nature of the flame generated is essential to their business purposes, or because the clean burning flame natural gas produces would not contaminate their product. On the other hand, flames necessary to produce heat in boilers never come in contact with the product.

The cost of conversion to an alternate fuel also is a factor in singling out boiler fuel uses for curtailment. The objective of section 401 of the NGPA is to protect supplies of natural gas to essential agricultural users of such natural gas who cannot use other fuels because these alternatives are not reasonably available or economically practicable. The low costs of conversion to other fuels, and the high volume of fuel use by boilers has led certain boiler fuel users to construct facilities which provide them the capability of using alternative energy sources. This factor obviously decreases the alternate fuel cost to those boiler fuel users. Alternatively, permitting boiler fuel users to use natural gas may well mean that during periods of curtailment, large volumes of gas would be diverted from other industrial uses for which substitute fuel is not even technologically feasible, to boiler fuel users.[1] The Commission believes that such a result would contravene the spirit and the letter of section 401 of the NGPA, and would be an improper regulatory approach.

The alternate fuel determination in section 401(b) rests on economic practicability and reasonable availability of alternate fuel. It does not specifically exclude propane and other gaseous fuels. Notwithstanding the historic FPC policy to exclude such fuels from its alternate fuel capability test the Commission proposed not to exclude by definition propane and other gaseous fuels from the new test: alternate fuel availability. As requested, many comments in Docket No. RM79–15, Permanent Rule Implementing Section 401(a) of the NGPA addressed this issue. It was generally asserted that the cost of these fuels made them uneconomic and their supply availability was directly related to the supply of natural gas. On these grounds, many parties advocated a generic exclusion of such fuels from

[1] Under the end-use principles that were used to develop most pipeline curtailment plans boiler fuel for the reasons discussed above received a low priority. Section 401 shifts agricultural curtailment policy and curtailment policy for high-priority users as defined in the statute to at least a partial end product basis. Thus, a substantial amount of boiler fuel might move from the lowest priority category to the highest priorty status.

the alternate fuel determination. The Commission finds it premature to adopt a policy on propane and other gaseous fuel at this time. Rather it will address the issue in the rulemakings on alternate fuel determination.

In summary, the Commission has tentatively decided to apply this rule to those boiler fuel users which can use in excess of 300 Mcf of natural gas on a peak day for purposes of triggering the procedures of this proposal. The conversion costs to alternate fuel of small boilers (*i.e.*, those using under 300 Mcf on a peak day) is substantially higher than the costs to larger boiler fuel users. The 300 Mcf per peak day use has been selected for several reasons. A 300 Mcf limit helps ensure that almost all small essential agricultural users would receive high-priority treatment, since such user's needs rarely exceed the 300 Mcf standard. Likewise, the number of small essential agricultural users who use under 300 Mcf and over 50 Mcf per day is substantial, and the administrative burdens of this proposal applying to them would be an inefficient use of Commission staff time and resources.

Notwithstanding its tentative conclusion to apply the alternate fuel test to large fuel users, the Commission seeks specific comment on whether it would be advisable to apply the test to all essential agricultural users. Recognizing the vast number of such users, it would clearly strain Commission resources unduly to apply the test to all users simultaneously.

Accordingly, if it were applied to all users, the Commission is considering dividing essential agricultural users into three categories and making the determinations sequentially for each category. The first category would be large boiler fuel users as covered by the proposed rule. The second category would be all other essential agricultural users except process and feedstock users. Last, process and feedstock users would be considered.

Procedures for application of the alternate fuel test

Section 401 states that the Commission may by rule or order make a determination regarding alternate fuel capability. There are at least three methods of making an alternate fuel determination. A determination of alternate fuel availability could be made by standards imposed by a generic rulemaking, a case-by-case order procedure, or a case-by-case rulemaking.

The Commission seeks comments on the use of a generic rulemaking which would adopt a rebuttable presumption that any essential agricultural user which has used a fuel other than natural gas continuously for 60 days during the three year period, 1976 through 1978, has alternate fuel which is reasonably available and economically practicable. Any essential agricultural user which sought to rebut the presumption would have the burden of establishing that alternate fuel was not economically practicable. The procedure for making such a rebuttal would be the adjustment procedures promulgated in accordance with such in 502(c) of the NGPA. These procedures are set forth in 18 CFR 1.41.

Another possible procedure is case-by-case orders. Under this method, the Commission would issue a notice in the Federal Register of each user which sought to classify natural gas as essential agricultural requirements. Any person including staff who wished to challenge the classification would file a protest and state the grounds therefor. If no protest were filed or no material questions of fact were raised in the filings, the Commission would issue an order, without a hearing, determining whether the essential agricultural user had alternate fuel which was reasonably available and economically practicable. Where a material question of fact were raised, an on-the-record proceeding would be conducted by an Administrative Law Judge (ALJ). The ALJ decision could be appealed to the Commission. in evaluating this

procedure, particular consideration should be given to the cost of the procedure to affected parties, both the essential agricultural user and protestants if the proceeding were before an ALJ. Parties may also wish to comment on whether they see any particular disadvantage to such a lengthy procedure given that the gas would be given Priority 2 treatement until a final decision on alternate fuel were made.

Finally the Commission is considering a case-by-case rulemaking applicable to large boiler users. the procedure is set forth in the proposed rule. This procedure appears to have several advantages over the case-by-case order described heretofore. first, many material questions of fact can be thoroughly reviewed and rebutted in a significantly less time consuming manner than required in an on-the-record proceeding. Thus, the case-by-case rulemaking balances the need for detailed fact finding with the need for expedition. Moreover, generally the expenses involved in participating in rulemaking proceedings are generally substantially less than the costs incurred by an active participant in an on-the-record proceeding.

A. Summary of the Proposed Rule

The purpose of the proposed rule is to establish a procedure for determining the economic practicability and reasonable availability of alternate fuel for essential agricultural use establishments which use natural gas as boiler fuel and which seek Priority 2 entitlements for that gas. The proposed rule provides that if an establishment meets the following three standards, the Commission will then conduct a rulemaking in order to determine whether the gas should receive Priority 2 treatment. The essential agricultural use establishment will be subject to the rulemaking if the establishment:

(a) Has the capacity to use more than 300 Mcf of natural gas on a peak day;

(b) Has, in fact, used a fuel other than natural gas as boiler fuel continuously for 60 days during the period 1976, through 1978; and

(c) Has requested or intends to request that its natural gas for boiler fuel use be classified as Priority 2 entitlement in the curtailment plan of its interstate pipeline suppplies.

Section-by-section summary of the rule

Purpose (§ 281.301). The rule establishes a procedure by which the Commission may determine alternate fuel availability under section 401(b) of the NGPA for certain establishments using natural gas as boiler fuel and for which Priority 2 entitlements are requested for that gas.

Applicability (§ 281.302). The proposed procedure would apply to any essential agricultural use establishment, as defined in § 281.303, which:

(a) Has requested or intends to request to have natural gas which will be used as boiler fuel classified by an interstate pipeline as a Priority 2 entitlement;

(b) Has the capacity to burn over 300 Mcf of gas on a peak day; and

(c) Has used a fuel other than natural gas for 60 consecutive days during 1976, 1977, or 1978.

Definitions (§ 281.303). "Alternate fuel" means any fuel, other than natural gas, which is economically practicable and reasonably available as a replacement for natural gas used as boiler fuel in an essential agricultural use establishment provided such fuel can be used without violating any applicable federal, state, or local pollution control standard.

"Boiler fuel" means that fuel used to generate steam or electricity, including electricity generated by gas turbines.

Other terms defined include "SIC Code," "essential agricultural user," "essential agricultural requirements," "Priority 2 entitlements" and "Form MA–100 or SU." "Essential agricultural use establishment" is defined in 7 CFR 2900.2(c).

General rule (§ 281.304). The Commission will conduct a rulemaking proceeding to determine if an essential agricultural establishment subject to this subpart has alternate fuel availability for the use of natural gas in each such establishment. Any such establishment

which requests Priority 2 classification for natural gas used as boiler fuel may receive such gas beginning November 1, 1979, unless the Commission finds alternate fuel capabilities. Upon such a finding, the essential agricultural requirement for gas used as boiler fuel must be returned, in amounts equal to the volumes of gas for which there is an alternate fuel, to the priority of service category where it would have been were it not for Priority 2 reclassification under subpart B.

Filing requirements (§ 281.305). Each essential agricultural use establishment subject to this subpart shall file with the Commission by June 15, 1979, a petition for rulemaking. The petition must contain at least the following data: (1) the name and address of the essential agricultural use establishment; (2) the total annual cost of boiler fuel for the establishment in 1976, 1977 and 1978, and the percentage of steam or electricity produced from boiler fuel use to treat essential agricultural products in each of those years; (3) the volume and cost of natural gas purchased for all purposes during 1976, 1977 and 1978 as required in Form MA–100 or SU, item A, line 5, with pertinent contracts and other information (also required, similar information on natural gas used as boiler fuel in those years); (4) the volume and cost of all fuels other than natural gas listed in the same forms for the same years; (5) the percentage of total volume of boiler fuel satisfied by non-purchased fuels as listed in the same forms; (6) the estimated volume, cost, terms, time period and availability of natural gas and the least expensive alternative fuel which could be used as boiler fuel under the applicable air pollution control laws for 1980; (7) the value of all products shipped from the establishment during 1976, 1977, and 1978 as listed in the above forms; (8) the annual payroll, supplemental labor costs, and each of the various costs of materials and services used in the establishment during the three years (as required by the above forms) and the estimated percentage of cost represented by the costs incurred as a result of activities qualifying the facility as an essential agricultural establishment.

An essential agricultural use establishment petitioning for a rulemaking may request confidential treatment of material submitted, according to paragraph (c).

Procedures for determination of alternate fuel availability. (§ *281.306*). Each petition for rulemaking filed by a boiler fuel facility pursuant to this proposal shall be published as a Notice of Proposed Rulemaking in the **Federal Register** and a copy of these will be sent to the Secretary of Agriculture. Written comments may be submitted by any interested person within 30 days of publication and copies of all comments will be sent to the petitioner. Copies of all petitions will be available to the public except insofar as any information is requested to be kept confidential. Such information may be released to any person requesting it, if the Commission's Secretary finds good cause to provide it. The material will be provided under a protective order wherein the recipient of the information swears that the material received will only be used in rulemaking. Any material designed confidential will be returned to the petitioner.

Under paragraph (c), each rulemaking will afford an opportunity for oral presentations of data, views and arguments. Any interested person submitting written comments may participate in the hearings by requesting the opportunity from the Commission Secretary. Notice of the hearing shall be published in the **Federal Register.** Any person submitting confidential information may request that the public hearing be closed except to those who submitted written comments.

Under paragraph (d), the Commission will issue a final rule based on all submitted data and information determining whether any one facility has alternate fuel capability. At the Commission's discretion, a rulemaking proceeding may be replaced with

alternate proceedings with respect to a particular establishment.

Written comment procedures. Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to May 30, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79–40.

Public hearing procedures. A public hearing concerning this proposal will be held in Washington, D.C. on May 23, 1979, beginning at 9:00 a.m. and will continue, if necessary, on the following day. The hearing will be held in Room 3200, 941 N. Capitol St., N.E., Washington, D.C. 20426. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on May 21, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM 79–40 as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing each person filing a request to participate will be contacted by the Presiding Officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m., on May 22, 1979. The Presiding Officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the Presiding Officer to be asked of persons making statements. The Presiding Officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the Presiding Officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Public Utility Regulatory Policies Act of 1978, Pub. L. 95–617; Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 stat. 3350; Department of Energy Organization Act, Pub. L. 95–91, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, it is proposed to amend Part 281, Subchapter I, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

PART 281—NATURAL GAS CURTAILMENT

1. Part 281 is amended in the table of sections by adding the appropriate numerical order new sections and titles (Subpart C) to read as follows:

Subpart C—Alternate Fuel Determination

Sec.
281.301 Purpose.
281.302 Applicability.
281.303 Definitions.
281.304 General rule.
281.305 Filing requirements.
281.306 Procedures for determination of alternate fuel availability.

Authority: Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.

2. Part 281 is amended to add a new Subpart C including § 281.301 through § 281.308 to read as follows:

Subpart C—Alternate Fuel Determination

§ 281.301 Purpose.

The purpose of this subpart is to establish a procedure for evaluation of the economic practicability and reasonable availability of alternate fuel, as prescribed in section 401(b) of the NGPA, for certain essential agricultural use establishments which seek priority 2 entitlements for natural gas to be used as boiler fuel. The evaluation will provide the basis for determination, by the Commission, of whether an alternate fuel to natural gas is available for boiler fuel use.

§ 281.302 Applicability.

This subpart applies to each essential agricultural use establishment:

(a) Which has requested or intends to request under § 281.207 to have natural gas which will be used for boiler fuel classified as priority 2 entitlements by an interstate pipeline;

(b) Which has capacity to burn in excess of 300 Mcf of natural gas on a peak day; and

(c) Which has actually used a fuel other than natural gas as boiler fuel continuously for 60 days during the period 1976 through 1978.

§ 281.303 Definitions.

For the purpose of this subpart:

(a) "Alternate fuel" means any fuel (1) which is economically practicable and reasonably available as an alternate to natural gas for use as boiler fuel and (2) which may be burned as boiler fuel without placing the essential agricultural use establishment in violation of any applicable Federal, state or local air pollution control standards.

(b) "Boiler fuel" means any fuel used for the generation of steam or electricity, including fuel used in gas turbines used to generate electricity.

(c) "SIC Code" means Standard Industrial Classification Code as set forth in the *Standard Industrial Classification Manual*, 1972 edition.

(d) "Essential agricultural user" means essential agricultural user as defined in § 281.203(b).

(e) "Essential agricultural requirements" means volumes certified by the Secretary of Agriculture and caculated in accordance with 7 CFR 2900.4.

(f) "Priority 2 entitlements" means the essential agricultural requirements of an essential agricultural user which an interstate pipeline classifies as priority 2 in its curtailment plan in accordance with Subpart B.

(g) "Essential agricultural use establishment" means essential agricultural use establishment as defined in 7 CFR 200.2(c).

(h) "Form MA-100 MU or SU" means Form MA-100 MU or SU of the Bureau of the Census for the Annual Survey of Manufacturers.

§ 281.304 General rule.

(a) The Commission shall conduct a separate rulemaking proceeding, of particular applicability, for each essential agricultural use establishment which is subject to this subpart to determine whether an alternate fuel to natural gas would be economically practicable and reasonably available for boiler fuel use by such essential agricultural use establishment.

(b) Any essential agricultural use establishment which has requested priority 2 classification for natural gas for boiler fuel use may receive such natural gas beginning November 1, 1979 in accordance with the provisions of Subpart B unless the Commission determines in accordance with the procedures of this subpart that the essential agricultural use establishment has alternate fuel.

(c) If the Commission determines that an essential agricultural use establishment has alternate fuel, it shall

require that the essential agricultural requirements equal to the natural gas volumes for which there is alternate fuel be removed, prospectively, from the priority 2 entitlements of the interstate pipeline and be replaced, prospectively, in the priority of service category of the interstate pipeline where they would have been included but for the reclassification to priority 2 under Subpart B.

§ 281.305 Filing Requirements.

(a) *General Rule.* Each essential agricultural use establishment which is subject to this subpart shall file a petition for rulemaking which shall contain the information specified in paragraph (b). The filling shall be addressed to the Secretary of the Commission and shall be filed by June 15, 1979.

(b) *Data requirement.* The petition for rulemaking shall contain, at the minimum, the following data concerning the essential agricultural use establishment:

(1) Name and address of the essential agricultural use establishment.

(2)(i) Total annual cost of boiler fuel for the essential agricultural use establishment in 1976, 1977 and 1978.

(ii) Percentage of steam or electricity produced from the boiler fuel which was used in the production or treatment of essential agricultural products in calendar years 1976, 1977 or 1978.

(3)(i) Indicate the volume and cost of natural gas purchased for all purposes during the calendar years 1976, 1977, and 1978, as required in Form MA–100 MU or SU, item 11—A, line 5. Indicate the time periods of use of the natural gas and pertinent terms of the contracts, or copies of the contracts.

(ii) Indicate the volume and cost of natural gas used as boiler fuel during calendar years 1976, 1977 and 1978. Indicate the time periods of use of the natural gas and pertinent terms of the contracts, or copies of the contracts.

(4)(i) Indicate the volume and cost of fuels other than natural gas purchased for all purposes, by types, during the calendar years 1976, 1977, and 1978, as required in Form MA–100 MU or SU, item 11—A. Indicate time periods of use of each such fuel and terms of the contracts, or copies of the contracts.

(ii) Indicate the volume and cost of fuels by type other than natural gas used as boiler fuel during calendar years 1976, 1977 and 1978. Indicate the time periods of use of the boiler fuel and pertinent contract terms or copies of the contracts.

(5) Indicate the percentage of the total volume of boiler fuel that is satisfied by non-purchased fuels, as required in Form MA–100 MU or SU, item 11–B part (b).

(6) Indicate the estimated volume, cost, terms, time period and availability of (i) natural gas and (ii) the least expensive fuel other than natural gas which may be used as boiler fuel under applicable Federal, state and local air pollution control standards for the calendar year 1980. The assumption and sources of the data used to develop all estimates should be summarized as necessary for the Commission to evaluate the estimates requested in this subparagraph.

(7) Indicate the value of all products, by SIC code, shipped from this essential agricultural use establishment during the calendar years 1976, 1977 and 1978, as required in form MA–100 MU or SU, item 14–A.

(8)(i) Indicate the annual payroll, supplemental labor costs, and each of the various costs of materials and services and the total of the various costs of materials and services used in this establishment for the calender years 1976, 1977, and 1978, as required in Form MA–100 MU or SU, items 3–A, 3–B and 5(a–f).

(ii) With respect to each cost and the total cost indicated in clause (i) estimate the percentage of such costs incurred because of activities which qualifies the establishment as an essential agricultural use establishment.

(c) If the essential agricultural use establishment wishes to request confidential treatment for information contained in the petition for rulemaking, it shall submit a second copy, with

confidential information deleted, with its petition for rulemaking.

§ 281.306 Procedures for determination of alternate fuel availability.

(a) *General rule.* Each petition for rulemaking filed under § 281.304 shall be issued by the Commission as a notice of proposed rulemaking. The notice shall be published in the **Federal Register** and sent to the Secretary of Agriculture.

(b) *Comments.* (1) Any interested person may submit written comments concerning the proposed rule within 30 days of publication of the notice of such rule. A copy of the comments shall also be sent to the essential agricultural use establishment that filed the petition under § 281.304.

(2)(i) Except as provided in paragraph (b)(2)(ii) of this section, any interested person may obtain from the Commission copies of any petition submitted under § 281.304(b).

(ii) Any person who seeks information required under § 281.305(b)(7) and (8) and for which confidential treatment has been requested shall file a petition under § 1.7 establishing the need for such information. If the Secretary of the Commission finds good cause to provide such information to the petitioner, it shall be released to such petitioner only in accordance with a protective order signed by the person receiving the information who swears, under oath, that the information shall be used only in the rulemaking proceeding and that all copies of the information shall be returned to the essential agricultural use establishment at the termination of the rulemaking proceeding.

(c) *Public hearings.* (1) An opportunity for public hearing shall be afforded with respect to each rulemaking, wherein oral presentations of data, views and arguments may be presented for consideration. Any person who has submitted written comments in accordance with paragraph (b) of this section may participate in the hearing by filing a written request to do so with the Commission's Secretary. The Commission shall publish in the **Federal Register** notice of the public hearing and dates by which requests to participate in such hearing must be filed.

(2) At the request of any person who has submitted confidential information, the public hearing for a particular request will be open only to those persons who have submitted written comments on such application.

(d) *Commission determination.* (1) Based upon all data submitted, consultation with the Secretary of Agriculture and other information available to the Commission, the Commission shall issue a final rule concerning each rulemaking for determination of alternate fuel availability.

(2) The Commission, in its discretion, may terminate a rulemaking proceeding and establish alternate procedures for determination of alternate fuel for a particular essential agricultural use establishment.

[Docket No. RM79-40]

¶ 32,022 Revision of Fuel Cost Adjustment Clause Regulations Relating to Fuel Purchases From Company-Owned or Company-Controlled Sources

44 F. R. 28683 (May 16, 1979)

Revision of Fuel Cost Adjustment Clause Regulations Relating to Fuel Purchases From Company-Owned or Company-Controlled Sources

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission is proposing to amend § 35.14(a) (6) and (7) of its Regulations under the Federal Power Act relating to fuel cost adjustment clauses. Specifically, § 35.14(a)(6) would be amended to make clear that, where a utility purchases fuel from a company-owned or company-controlled source, costs reflecting fuel handling, fuel storage and fuel financing may not be passed through the fuel cost adjustment clause. The proposed amendment to § 35.14(a)(7) would require utilities to file with the Commission as rate schedules all contracts for fuel purchases from company-owned or company-controlled sources, regardless of whether the price of such purchase is subject to the jurisdiction of a regulatory body.

DATE: Written comments must be filed by July 2, 1979.

ADDRESSES: All filings should reference Docket No RM79-41 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Michael A. Coleman, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-4728.

Bonnie Cord, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-0422.

SUPPLEMENTARY INFORMATION: Notice is hereby given that the Commission is proposing to amend § 35.14 of its regulations under the Federal Power Act, relating to fuel cost adjustment clauses. Specifically this notice proposes to amend § 35.14(a)(6) to make clear that, where fuel is purchased from company-owned or company-controlled sources, certain cost items may not be included in the fuel cost adjustment clause. The Commission also proposes an amendment to § 35.14(a)(7) to require utilities to file with the Commission as rate schedules all contracts for fuel purchases from company-owned or company-controlled sources, regardless of whether the price is subject to the jurisdiction of a regulatory body.

Background

The purpose of § 35.14 is to allow an electric utility's fluctuations in fuel costs to be promply reflected in its revenues. This is accomplished by means of a fuel cost adjustment clause which allows an electric utility to automatically pass through to its customers changes in the utility's cost of fuel. Because the pass-through is automatic, the administrative proceeding, otherwise necessary to approve the pass-through, is eliminated. The elimination of the administrative proceeding is beneficial to the utility because it reduces the time period between the utility's payment of the increased fuel prices and its recovery of the increase from its customers. It is also beneficial to the utility's customers, the public and the Commission, as well as the utility, in that it eliminates the cost and burden of additional formal rate proceedings and promptly passes through reductions in fuel costs.

However, because the increased costs may be passed through without prior approval, the Commission has a responsibility to make sure that the utility is purchasing its fuel at

reasonable prices and that only allowable costs are recovered through the fuel cost adjustment clause. In order to carry out this responsibility, the Commission has established several mechanisms by which it may monitor and investigate costs recovered through fuel cost adjustment clauses, including: (1) Compliance audits conducted by the Commission's audit staff as part of its regular program of field audits of the books and records of public utilities subject to the Commission's jurisdiction; (2) review and investigation of fuel costs in conjunction with the Commission's analyses of specific proposed wholesale rate changes; and (3) investigations of fuel costs under section 206 of the Federal Power Act instituted either upon complaint or upon the Commission's own motion. Section 35.14(a)(7), in its present form, provides an additional means of monitoring the use of fuel adjustment clauses in that it requires utilities to file with the Commission, in certain cases, contracts governing the utilities' purchases of fuel from an affiliate.

Summary of the Proposed Regulations

Section 35.14(a)(6) states in part that "the cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees." The purpose of this statement is to make clear that only items which are properly attributable to the cost of the fuel may be included in the fuel cost adjustment clause. Where a utility obtains fuel from an integrated supplier, certain costs incurred by the utility, such as fuel handling, fuel storage and fuel financing, are not includable in Account 151, nor eligible for pass-through in the fuel adjustment clause. The Commission has determined that, likewise, such items are not properly includable in Account 151 where the utility purchases fuel from a non-integrated affiliate, even though the utility is billed for such services. *Southern California Edison Company*, Docket No. E-8570, order issued April 26, 1978. Accordingly, the Commission proposes to amend § 35.14(a)(6) to make clear that where a utility purchases fuel from an affiliate, costs reflecting fuel handling, fuel storage and fuel financing are not includable in Account 151 and may not be passed through the fuel cost adjustment clause, even though they may be included in the invoice price.

Section 35.14(a)(7), in its present form, provides in part that where a regulatory body has jurisdiction over the price of fuel purchased by a utility form a company-owned or company-controlled source, the cost of fuel so purchased shall be deemed to be reasonable and includable in the fuel adjustment clause. This section further provides that where no regulatory body has jurisdiction over the contracts governing the price of fuel purchases by a utility from an affiliate, the utility must file the contracts with the Commission for Commission acceptance at the time the utility files its fuel clause or modification thereof. In order to further aid the Commission in fulfilling its responsibility to ensure that utilities are purchasing fuel at reasonable prices and that only allowable costs are being passed through in the fuel cost adjustment clause, the Commission proposes to amend § 35.14(a)(7) to require that a utility file contracts governing the price of fuel purchases from company-owned or company-controlled sources, regardless of whether the price is subject to the jurisdiction of a regulatory body.

Public Comment Procedures

Interested persons may participate in this proposed rulemaking by submitting written data, views or argumants to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, by July 2, 1979.

Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-41) and give reasons for any recommnedations. An original and 14 conformed copies should be filed with the Secretary of the Commission.

Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

(Federal Power Act, as amended (16 U.S.C. 791 *et seq.*), Department of Energy Organization Act (42 U.S.C. 7107 *et seq.*), E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, the Commission proposes to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

Section 35.14 is amended by revising subparagraphs (6) and (7) of paragraph (a) to read as follows:

§ 35.14 Fuel cost adjustment clause.

(a) * * *

(6) The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. For purposes of Account 151, the invoice price of fuel as that term is used in that Account does not include costs for fuel handling, fuel storage, and fuel financing incurred (i) directly by a utility (rather than by any other person and billed to the utility), or (ii) as part of a purchase from company-owned or controlled sources (as defined in the Commission's Uniform System of Accounts, 18 CFR Part 101, Definitions 5B). The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account. (Paragraph C of Account 518 includes the cost of other fuels used for ancillary steam facilities.)

(7) Where the cost of fuel includes fuel from company-owned or controlled sources (as defined in the Commission's Uniform System of Accounts 18 CFR Part 101, Definitions 5B) that fact shall be noted and described as part of any filing. With respect to the price of fuel purchases from company-owned or controlled sources, the utility company shall file such contracts and amendments thereto with the Commission for its acceptance at the time it files fuel clause or modification thereof. Any subsequent amendment to such contracts shall likewise be filed with the Commission as a rate schedule change and may be subject to suspension under Section 205 of the Federal Power Act. Fuel charges by affiliated companies which do not appear to be reasonable may result in the suspension of the fuel adjustment clause or cause an investigation thereof to be made by the Commission on its own motion under section 206 of the Federal Power Act.

* * * * *

[Docket No. RM 79-41]

¶ 32,023 Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978

44 F. R. 29090 (May 18, 1979)

[18 CFR Part 282]

[Docket No. RM79-21]

Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978

Issued: May 11, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking and Opportunity for Written and Oral Presentation of Data, Views, and Arguments.

SUMMARY: The Federal Energy Regulatory Commission hereby gives notice of a proposed rulemaking and public hearings for the purpose of implementing one aspect of the incremental pricing provisions of the Natural Gas Policy Act of 1978. Specifically, the notice contains regulations establishing alternative fuel price ceilings for incremental pricing purposes.

DATES: Comments by June 19, 1979. Requests to speak: *St. Paul, Minnesota hearing:* by May 30, 1979; *Los Angeles, California hearing:* by June 1, 1979; *Atlanta, Georgia hearing:* by June 8, 1979; *Washington, D.C. hearing:* by June 11, 1979. Hearing dates: *St. Paul, Minnesota hearing:* June 6, 1979, 9:30 a.m.; *Los Angeles, California hearing:* June 8, 1979, 9:00 a.m.; *Atlanta, Georgia hearing:* June 15, 1979, 9:00 a.m.; *Washington, D.C. hearing:* June 18, 1979, 10:00 a.m.

ADDRESSES: All comments and requests to speak should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM79-21).

HEARING LOCATIONS: *St. Paul, Minnesota hearing:* Minnesota Public Service Commission, 7th Floor, American Center Building, Kellogg and Robert Streets, St. Paul, Minnesota 55101; *Los Angeles, California hearing:* State Building, 107 S. Broadway, Los Angeles, California 90016; *Atlanta, Georgia hearing:* Georgia Public Service Commission, 162 State Office Building, 244 Washington Street S.W., Atlanta, Georgia 30334; *Washington, D.C. hearing:* Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Hearing Room A, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Norman A. Pedersen, Federal Energy Regulatory Commission, Room 9006, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4147.

James C. Liles, Federal Energy Regulatory Commission, Room 3106, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4121.

Nancy E. Williams, Federal Energy Regulatory Commission, Room 8100F, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-0422.

I. Background

The Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621), signed into law on November 9, 1978, mandated a new framework for the regulation of most facets of the natural gas industry. The regulations described in this Notice are proposed for purposes of implementing Title II of the NGPA, "Incremental Pricing", and, particularly, subsection 204(e).

In general, under Title II, interstate pipeline companies are required to pass through portions of their acquisition costs for natural gas to industrial users in the form of a surcharge. The statute

requires that the surcharge placed on industrial users be such that the ultimate cost of gas to the user does not exceed the cost of the fuel oil which he would use as an alternative.

The incremental pricing program is to be implemented in two phases. The only facilities affected during the first phase will be those using natural gas as fuel for large industrial boilers. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979.

During the second phase of the program, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The regulations implementing the second phase must be promulgated by May 9, 1980 and will be subject to Congressional review.

This docket, RM79–21, and the regulations set forth below, involve only the implementation of the alternative fuel cost ceilings on incremental pricing, as required by section 204 of the NGPA. In this notice the Commission addresses the issue of whether the appropriate alternative fuel cost to be used in determining the ceiling should be reduced from the level of No. 2 fuel oil.

The other regulations which are needed to implement the first phase of the incremental pricing program will be promulgated in Docket No. RM79–14. That docket will involve both the regulations prescribing the mechanism for incremental pricing and the regulations establishing procedures for obtaining exemptions under section 206 of the NGPA. It is currently anticipated that a notice of proposed rulemaking will be issued in Docket No. RM79–14 within the next few weeks.

II. Public Input to This Proposed Rulemaking

In the course of developing the proposed regulations set forth below, the Commission staff has held informal public discussions with state officials, other representatives of the regulatory community, and various sectors of the natural gas industry. The public conferences have provided a forum for the open exchange of ideas and information on many aspects of the NGPA incremental pricing provisions.

The first conference was held on February 12, 1979 in Docket No. RM79–14. notice of this conference was issued on January 12, 1979 (44 FR 6133, January 31, 1979). A preliminary proposal which had been developed by Commission staff for the implementation of the surcharge passthrough provisions of Title II was included in the January 12th notice. This conference was attended by representatives of many sectors of the natural gas industry—pipeline companies, industry associations, distribution companies, and consumers. On February 22, 1979, the Commission staff held a discussion with representatives of the National Association of Regulatory Utility Commissioners to discuss issues involved in the implementation of incremental pricing. Attending the conference were Chairman Kati Sasseville of the Minnesota Public Service Commission, Commissioner Carmel C. Marr of the New York Public Service Commission and Commissioner Leigh H. Hammond of the North Carolina Utilities Commission.

Additional informal conferences were held on April 2–4, 1979. The April 2nd conference was called in this docket, RM79–21, to give interested parties an opportunity to address the issue of the alternative fuel cost ceiling on incremental prices. In the Notice convening the conference (issued March 14, 1979 (44 FR 16937, March 20, 1979)), conference participants were asked to discuss eight issues regarding establishment of an appropriate alternative fuel cost:

1. Should the alternative fuel cost ceiling be based on the cost of no. 2 fuel oil, the cost of No. 6 fuel oil or someting in between?

2. What should be the regions for which alternative fuel cost ceilings should be determined?

3. Should the ceiling be based on the wholesale price of fuel oil or the retail price?

4. Should the alternative fuel cost ceiling be based on the price quoted for fuel oil before state and local taxes are included, or should the ceiling be based on the price after state and local taxes are included?

5. What should be the length of the period for which weighted averages should be taken in deriving alternative fuel cost ceilings from oil price data?

6. Should there be a downward adjustment of the average cost of oil? If so, what should be the factor by which there will be a downward adjustment?

7. How often should data on fuel oil prices be collected?

8. How frequently should the ceiling be published?

The April 3rd conference (noticed on March 16, 1979 (44 FR 17526, March 22, 1979)) was convened in Docket No. RM79-14 to discuss the various mechanisms for implementation of the surcharge passthrough provisions which were suggested by participants in the February 12th conference.

On April 4 and 12, 1979, the Commission staff had further meetings with members of the National Association of Regulatory Utility Commissioners to discuss issues regarding the incremental pricing program. Present were Commissioner John C. Pickett and Commissioner N. M. Norton, Jr., of the Arkansas Public Service Commission, Commissioner Robert Fischbach of the North Carolina Utilities Commission, and representatives of the state commissions of Illinois, Michigan, California, Wisconsin, New York, Maryland, the District of Columbia, Virginia, Connecticut, Oklahoma and Ohio.

The February and April conferences were very helpful. The Commission expresses its sincere appreciation to all who participated.

All of these formal conferences were transcribed. The transcripts and the written comments provided to the Commission have been made available for public inspection in the Commission's Office of Public Information. The transcripts and written comments associated with the conferences convened in Docket No. RM79-21 shall be part of the public record upon which the final rulemaking in that docket will be based. Similarly, the transcripts and written comments filed in connection with the conferences convened in Docket No. RM79-14 shall be part of the public record in that proceeding.

III. Proposed Regulations

Section 204 of the NGPA sets forth provisions regarding the manner in which incremental costs of natural gas, as defined in the Act, are to be passed through to industrial boiler fuel facilities subject to the incremental pricing program. Those costs are to be billed as a surcharge. There is, however, a ceiling on how high incremental pricing can take the cost of gas billed to industrial boiler facilities. Subsection (e) of section 204 directs that the ceiling shall be set at the level paid by industrial users for No. 2 fuel oil, unless the Commission determines that the ceiling should be lowered to a point not lower than the price paid for No. 6 fuel oil. The statute states:

Sec. 204 Method of Passthrough

* * * * *

(e) Determination of Alternative Fuel Cost.—(1) In General.—Except as provided in paragraph (2), the appropriate alternative fuel cost for any region (as designation by the Commission) shall be the price, per million Btu's, for Number 2 fuel oil determined by the Commission to be paid in such region by inddustrial users of such fuel.

(2) Reduction of Appropriate Alternative Fuel.—The Commission may, by rule or order, reduce the appropriate alternative fuel cost—

(A) For any category of incrementally priced industrial facilities, subject to the rule required under section 201 (including any amendment under section 202 to such rule) located within any region and served by the same interstate pipeline; or

(B) For any specific incrementally priced industrial facility which is subject to such requirements and which is located in any region;

to an amount now lower than the price, per million Btu's, for the Number 6 fuel oil

determined by the Commission to be paid in such region by industrial users of such fuel, if and to the extent the Commission determines, after an opportunity for written and oral presentation of views, data, and arguments, that such reduction is necessary to prevent increases in the rates and charges to residential, small commercial, and other high-priority users of natural gas which would result from a reallocation of costs caused by the conversion of such industrial facility or facilities from natural gas to other fuels, which conversion is likely to occur if the level of the appropriate alternative fuel cost were not so reduced.

The Commission believes that the Congressional intent expressed in subsection 204(e) is that the incremental pricing program should not serve to encourage industrial users to switch from natural gas to fuel oil if such switching would result in increased rates for residential and small commercial customers. Accordingly, if setting the alternative fuel cost ceiling at the level of No. 2 fuel oil would be likely to cause fuel switching and a shifting of capital costs from industrial to residential and commercial customers, the ceiling should be reduced in a manner so as to minimize the likelihood of fuel switching. The Commission is mindful of the Congressional admonition that it act expeditiously to prevent incremental pricing pricing from causing load loss and, hence, higher costs to high priority users:[1]

The conferees urge the Commission to take whatever action it deems appropriate or necessary * * * to avoid any delays in reducing the substitute fuel level so as to avoid the likelihood of conversions from natural gas by industrial users if those conversions would result in increases in natural gas rates for any residential, small commercial, and other high priority customers. The conferees intend that in determining the likelihood of these conversions occurring, the Commission move rapidly in the administering hearings so as to avoid the irreparable damage which the conferees believe will occur to high priority users if these believe will occur to high priority users if thee other industrial users, faced with uncertain natural gas rates, begin taking steps to secure alternate fuel supplies.

A related concern is, of course, the substantial dependence of the United States on imported crude oil. Any increased use of fuel oil by industrial users would only serve to exacerbate this situation.

While, however, the ceiling should be reduced so as to minimize the likelihood of fuel switching and its consequences, the Commission believes that the ceiling should be reduced only as much as necessary to realize that goal. The basic purpose of incremental pricing under Title II is to direct to industrial users, to the greatest extent possible, the increased acquisition costs of natural gas resulting from the provisions of the NGPA. Any reduction in the alternative fuel cost ceiling below the point necessary to prevent fuel switching would be contrary to that purpose. Thus, the Commission must, in its implementation of subsection 204(e), strike a balance between the two goals of maximizing flow-through of incremental costs to industrial facilities and minimizing fuel switching. Setting the alternative fuel cost ceiling gives rise to a number of issues which involve striking the proper balance between these two goals. The discussion which follows is structured around those issues.

A. No. 2 or No. 6

The predominant question with respect to the implementation of subsection 204(e) is whether the alternative fuel cost ceiling should be reduced from the level of No. 2 fuel oil to the level of No. 6. Many of the commenters participating in the April 2nd conference urged that the alternative fuel cost ceiling be set at the level of No. 6 fuel oil rather than No. 2 in order to deter, to the greatest extent possible, any loss of industrial load. Experiences with load shifting were recounted, and situations were

[1] S. Rep. No. 95-1752, 95th Cong., 2nd Sess. 100 (1978).

described in which fuel switching to the detriment of high-priority consumers might occur. Commenters stated that the alternative fuel for large industrial boilers is usually No. 6 oil, not No. 2. They stated that the operators of large boilers make decisions on an almost daily basis as to their use of fuel—opting for that which bears the lowest price.

The American Gas Association (AGA) submitted the results of a survey it conducted of member companies on the question of where the alternative fuel cost ceiling should be set. Based on the results of that survey, the AGA concluded that if the alternative fuel cost ceiling were established at the No. 2 rather than No. 6 level, at least 741 billion cubic feet (Bcf) of industrial sales would be lost in the year 1980.

The view that there would be substantial load loss and shifting of capital costs if the ceiling were not reduced was broadly supported by participants at the conference. The Public Staff of the North Carolina Utilities Commission submitted an analysis of the industrial service currently provided by the Public Service Company, one of three gas utility companies serving North Carolina. This study showed that of industrial boiler fuel users served by that utility, 87.75 percent, based on volumetric use, have a capability to use No. 6 fuel oil, and 8 percent have the capability to use No. 5 fuel oil. The Public Staff also estimated the effect a loss of these industrial customers would have on the Public Service Company's rates. By looking only at industrial facilities using in excess of 300 Mcf per day—the category of facilities subject to the first phase of the incremental pricing regulations—the Public Staff calculated that the loss of the users who have the capability to use No. 5 and No. 6 fuel oil would mean an increase in the rates to remaining customers on the system of 14.7 cents per decatherm.

The Northern Natural Gas Company said there are approximately 60 customers on its system which will be subject to the first phase of the incremental pricing program. Northern Natural estimated that these customers will, in 1980, use approximately 3.5 percent of the volume of natural gas sold by Northern. Northern found through discussions with its customers that for approximately one-half of the gas volumes consumed by the large industrial users, No. 6 fuel oil is the alternative fuel. Thus, Northern anticipates that there would be a substantial loss of industrial sales if the alternative fuel cost ceiling remained at the No. 2 level.

The State of Louisiana commented that large industrial boilers in Louisiana equipped to burn No. 6 fuel oil outnumber by more than 3 to 1 boilers that are equipped to burn No. 2 fuel oil. the Mississippi River Transmission Corporation submitted an estimate that approximately 20 percent of its total volume of direct sales go to large industrial users who are equipped to burn No. 6 fuel oil.

The Pacific Gas and Electric Company (PG&E), which serves customers in northern California, submitted comments showing that since 1975 it has already lost 110 Bcf of sales due to customers shifting to alternate fuels for economic reasons. PG&E stated that each ten billion cubic feet of gas sales to industrial customers provides approximately $5 million of revenue to help offset fixed costs, giving an indication of the proportion of fixed costs that industrial users absorb.

The comments received to date have covered a spectrum of the interests affected by incremental pricing. Of particular interest is the fact that all state utility commissions which have commented to date—bodies which represent views to which this Commission must give special consideration—have cautioned that a ceiling set at the No. 2 fuel oil level would result in significant conversions to fuel oil for boiler fuel purposes.

In addition to the comments, the Commission has available to it data obtained by the Energy Information

Administration (EIA). In December 1978, the Energy Information Administration of DOE sent a questionnaire, Form EIA-134 to interstate pipelines, local distribution companies, state commissions and other interested persons to gather information, on a voluntary basis, about the alternative fuel capabilities of both large and small industrial boilers. EIA also solicited opinions as to what the ceiling should be. The Commission has examined the results of this survey, bearing in mind that the responses were voluntary and thus do not constitute a statistically valid sample. The survey indicated that a significant number of boiler fuel facilities in a majority of the states are equipped to burn No. 6 fuel oil. Further, the majority of respondents favored a ceiling based on the No. 6 oil price. However, the survey also indicated that there are a number of boiler fuel facilities which will be subject to the first phase of the incremental pricing program that only have an alternative fuel capability to use No. 2 fuel oil.

The Commission has also analyzed the data reported on the EIA-50 form. EIA-50 is used to gather information on the alternative fuels that are used to offset curtailments in the delivery of natural gas. Analysis indicates that during the period April 1977—March 1978, large industrial users utilized No. 5 or No. 6 fuel oil to offset approximately 40 percent of the natural gas curtailment they experienced. This percentage translates to approximately 64 million barrels of oil. The EIA-50 data also indicate that No. 1 and No. 2 fuel oil was utilized to offset approximately 20 percent of natural gas curtailments during the same period.

Thus, both the comments received at the April 2nd conference and the data available to the Commission from EIA tend to show that there is a singificant likelihood of widespread conversion from gas to No. 6 fuel oil if the alternative fuel cost ceiling were set uniformly at the level of No. 2 fuel oil prices. The precise amount of the shift cannot be statistically determined from the available data and comments. Nor can the effect on high-priority consumers be estimated. However, there is a clear likelihood that sizable shifts from gas to oil could occur. On the other hand, however, it has not been shown that it is necessary to reduce the alternative fuel cost ceiling to the No. 6 level for all industrial boiler fuel users in order to prevent conversions from gas to oil and a shifting of capital costs to high-priority customers.

The question of where to set the alternative fuel cost ceiling must be addressed with great caution. The Commission is aware that an inappropriate ceiling could have an extremely serious adverse impact on the natural gas industry and its customers. The results could potentially be irreparable if a pipeline or distribution company were unable to replace lost industrial load with either new industrial load or new high-priority use. And even if new high-priority load could be added over time, in all probability it could not be added quickly enough to compensate for sudden large losses of industrial load.[2] Moreover, the Commission is cognizant of the public policy impact an inappropriate action would have with respect to the country's demand for additional supplies of imported crude oil.

In order to balance these concerns with the Congressional intent that incremental costs be borne by industrial customers to the maximum extent possible, the Commission proposes that three alternative fuel cost ceilings be established for each region of the country—one at the level of No. 2 fuel oil, another at the level of high sulfur No. 6 fuel oil and a third at the level of low sulfur No. 6 fuel oil. Industrial boiler fuel facilities would be incrementally priced only up to the level of the lowest priced fuel oil which they could in fact use. This approach would avoid the establishment of a blanket ceiling for all

[2] Further, even if new high-priority load were attached to offset the loss of industrial load, additional storage might be required.

users—one which might be too high for some users, and thus result in their loss to the system, while being too low for other users, allowing them to escape some of the costs which Congress intended they should bear under the incremental pricing program.

In the proposed regulations, "high sulfur" oil is defined as oil containing over 1 percent sulfur. "Low sulfur" oil is oil containing 1 percent or less sulfur. The Commission proposes to have different ceilings for high and low sulfur No. 6 fuel oil because the information available to the Commission indicates that the price differential between the two categories of No. 6 oil can be as great as that between No. 2 and No. 6 prices. In a letter dated April 24, 1979, the Assistant Secretary for Policy and Evaluation of the Department of Energy urged the Commission to consider the variations in No. 6 fuel oil prices due to sulfur content. The Assistant Secretary noted that, using data compiled by the Energy Information Administration of DOE, No. 6 fuel oil containing .3 percent or less sulfur has at times carried a price 36 cents higher, on a per million Btu basis, than No. 6 fuel oil with more than 1 percent sulfur. Furthermore, due to legal restrictions having to do with air quality standards, there may be a large number of boilers which are equipped to utilize only low-sulfur No. 6 oil.

Under the proposal contained in the attached proposed rule, there would be a certification procedure for determining the alternative fuel capability of industrial boiler fuel facilities which are not exempt from incremental pricing.[3] If a facility is technically able and legally permitted to burn low sulfur No. 6 fuel oil, or if a facility is technically able and legally permitted to burn high sulfur No. 6 fuel oil, a responsible official of the facility may so certify. If there were such a certification, a non-exempt industrial boiler fuel facility would be incrementally priced at the level of the lowest priced alternative fuel—No. 6 low sulfur fuel oil or No. 6 high sulfur fuel oil—which the facility had been certified as being capable of burning. If there were no such certification of legal and technical capability to burn either low or high sulfur No. 6 fuel oil, a non-exempt facility would be deemed to have the capability to burn No. 2 fuel oil and would be incrementally priced at that level.

Certifications would be made through the filing of an alternative fuel capability form, signed under oath by a responsible company official, with the Commission. A copy of the executed form would be filed with the natural gas supplier serving the facility. Blank forms would be supplied to industrial customers by their supplier at the same time that forms requesting exemptions are supplied,[4] September 1, 1979, and they would be available on an ongoing basis after that for the benefit of firms which subsequently install No. 6 alternative fuel capability. If a facility is not equipped to burn a No. 6 oil, but such capability is later installed, the certification could be filed at a later date.

The proposed regulations require that owners retain any documents showing that a facility is equipped with alternative fuel capability for a period of three years following the first billing by a natural gas supplier under the program which reflects a surcharge at one of the two No. 6 alternate fuel prices. The type of proof which would fulfill this requirement, aside from the alternative equipment itself, would be, for example, bills for the actual installation of the equipment, a qualified engineer's report that capability is in place, bills for purchases of No. 6 fuel oil, or contracts for the supply of No. 6 oil. This retention of records would allow for the audit of filed certifications by Commission enforcement personnel. An affiant will be required to describe on his alternative fuel capability form what he will retain as evidence for his claim that his facility is capable of burning a No. 6 oil.

[3] The procedure for obtaining an exemption will be addressed in detail in the notice of proposed rulemaking in Docket No. RM79-14. It is requested, therefore, that comments submitted in this docket, RM79-21, not address the exemption issue.

[4] See footnote 3 on previous page.

The certification required under this approach will only have to be filed once and, thus, should not place a significant burden on industrial end-users.

A natural gas supplier will be required to have available for public inspection all alternative fuel capability forms he has received. Additionally, all such forms filed with the Commission will be available to the public. Any interested person who desires to protest any certification of alternative fuel capability may do so by filing a protest in accordance with section 1.10 of the Commission's Rules of Practice and Procedure.

Any industrial user which believes that the self-certification procedure imposes a special hardship on him may request administrative relief under the adjustment procedures which were recently promulgated as interim regulations by the Commission (Order No. 24, issued on March 22, 1979 in Docket No. RM79-32).

The Commission believes that the three-tiered ceiling described above represents an appropriately cautious approach which should be adopted in the initial stage of the incremental pricing program. Retention of the No. 2 ceiling established in section 204(e) of the NGPA would, the Commission believes on the basis of the data and comments now before it, be likely to lead to fuel switching and a shifting of capital costs to high-priority customers. An across-the-board reduction of the ceiling to the level of No. 6 fuel oil would, however, fail to maximize flow-through of incremental costs to industrial users, insofar as some industrial facilities are either legally or technically incapable of using No. 6 oil.

The Commission requests comments on the three-tiered approach. Particularly, the Commission requests comments as to whether modifications to the three-tiered approach described above are required to provide for situations where an industrial facility has an alternative fuel capability to utilize a fuel of a quality between No. 2 and either low or high sulfur No. 6 fuel oil. No. 4 or No. 5 fuel oil are often obtained by blending No. 2 and No. 6. Where No. 2 and No. 6 are blended, it is very possible the alternative fuel thus obtained carries a lower net acquisition cost than No. 2 does by itself. Thus, it might be appropriate to permit an industrial user using a blend to have an alternative fuel ceiling below that set for No. 2, though above the No. 6 ceiling levels. Commenters on this issue are requested to submit as much data as possible. If a regulatory solution is recommended, commenters are requested to submit regulatory language which they believe would address the problem effectively.

Under the proposed rule, technical capability and legal ability to use various fuels would determine what ceiling would apply to a specific facility. The Commission requests commenters to provide information about the extent of No. 6 fuel burning capability generally and by category of user and region.

Additionally, the Commission asks commenters to address the question of whether, if it is shown that there is widespread technical capability and legal ability to switch from gas to No. 6 fuel oil, it is legal and appropriate for the Commission, on the basis of its expertise and knowledge of gas pricing policy and economics, to infer that there would be a likelihood of fuel switching with an adverse shifting of capital costs to high priority customes.

B. *Regions*

Subsection 204(e) gives the Commission the flexibility to determine the regions for which alternative fuel price ceilings shall be established.

The majority of industry participants in the April 2nd conference encouraged the Commission to establish alternate fuel price ceilings for each Standard Metropolitan Statistical Area (SMSA). These commenters stated that market conditions vary from one metropolitan area to another, and from a metropolitan area of a state to a rural area. Several of the factors involved in the establishment of oil prices were described, such as transportation costs, air quality standards, the relative availability of oil

in a given region, the size and conditions of a purchase, and the quality of the oil purchased. By establishing ceilings for each SMSA, commenters suggested that the ceilings would be more sensitive to the conditions existing in any particular area.

Some commenters urged that the incremental pricing regions should be the service areas of local gas distribution companies. These commenters stated that this approach would permit each company to continue to maintain uniform rates throughout its service area.

The representatives of individual states who commented on this issue were unanimous in urging that states be the regions. A few commenters stated that large multi-state regions would best serve the purposes of subsection 204(e).

In deciding what the incremental pricing regions should be, there are five standards which should be considered: (1) the number of regions should be a manageable number from an administrative point of view; (2) each region should be such that prices charged to end-users will be reasonably close to the average for the region; (3) each region should include enough oil users to obtain a statistically meaningful sample size; (4) regions should be rationally related to industrial concentrations and fuel oil marketing areas; and (5) the regions should be as consistent with political boundaries as possible.

The Commission staff suggested three approaches which would be administratively workable and would satisfy to a large degree the five criteria above. These would be: (1) to use states as regions; (2) to divide the continental United States into eight large multi-state regions; or (3) to use the eight large multi-state regions, but break out from them the 31 metropolitan regions which have a population of one million or above.

The Commission proposes to adopt the third approach, which would result in the establishment of alternative fuel price ceilings for 39 separate regions. A list of the 39 regions and a map indicating them is attached as an Appendix to the regulations set forth below. The 31 metropolitan areas with a population of one million or more were derived from data gathered by the Bureau of the Census of the United States Department of Commerce. They reflect either SMSA's or Consolidated Metropolitan Statistical Areas (CMSA's). Like SMSA's and CMSA's, the metropolitan regions observe county boundaries. The eight large multi-state regions were derived by modifying various regional divisions used by the Bureau of the Census, the Department of Energy and others to take into account energy production, distribution and sale patterns.

Hawaii and Alaska are not included in any of the regions, since neither state will be affected by the initial phases of the incremental pricing program. Neither presently utilizes gas from nor produces gas for the interstate market.

The metropolitan/multi-state region approach would permit the establishment of alternative fuel price ceilings which, to a substantial degree, would reflect market conditions in discrete marketing areas, but it would avoid the administrative burden involved in establishing prices for nearly 300 SMSA's. There should be a relatively small dispersion of observed prices around the mean, and sample size will probably be adequate. The nation's larger industrial and oil marketing concentrations are recognized, and state or county boundaries are followed.

The Commission believes that the metropolitan/multi-state approach is preferable to using states, since state boundaries frequently do not bear a rational relationship to industrial or oil marketing areas. The approach is also preferable to using distribution company service areas since some distribution companies, for example, Atlanta Gas, service non-contiguous and divergent areas.

The Commission requests comments both on the proposed approach and on, especially, two other possible approaches: the use of states as regions and the use of large multi-state regions.

If the comments submitted in response to this notice present persuasive reasons for adopting one of these other approaches, the Commission hereby gives notice that it may do so in promulgating a final rule.

C. *Data Collection*

The Commission proposes to request that the Energy Information Administration (EIA), in its role as the data collection agency of the Department [5], gather the data necessary to determine alternative fuel prices charged to industrial users in each region and to process that data in order to arrive at three ceiling levels for each incremental pricing region.[6]

EIA would be requested to gather before-tax data on the prices charged to large, non-utility industrial users for sales made on a contract basis for large lots of No. 2 fuel oil, high sulfur No. 6 fuel oil and low sulfur No. 6 fuel oil. The data would be collected from sellers rather than purchasers. Respondents would be asked to identify the regions, based on a facsimile of the map which is appended to the regulations below, to which the sales for which prices are provided are being made. For any case in which a meaningful sample cannot be obtained for a region, the EIA will be requested to derive a price in accordance with appropriate statistical methodology.

1. *Data Collection from Sellers Rather Than Purchasers.*—It is proposed that EIA collect prices on the three alternative fuels from firms selling the fuels rather than from purchasers for the following reasons. First, the EIA currently collects data on No. 2 prices on a regular basis, and this collection effort can easily be adapted to the requirements of the incremental pricing program. Second, it is EIA's experience that collection of price data from end-users of a product is very difficult. If they do not respond voluntarily, enforcing compliance is a lengthy and burdensome task. Further, end-users who are using both fuel oil and natural gas would have an incentive to misreport the prices they are paying for fuel oil in order to lower their potential price for natural gas.

2. *Large Lot Sales Data.*—No. 6 fuel oil is typically sold in large quantities and priced on such a basis. No. 2 fuel oil sold for boiler fuel use in large industrial facilities is also sold and priced in large quantities. Since the first phase of the incremental pricing program involves large industrial boiler fuel facilities, it is proposed that the data on which the alternative fuel cost ceilings will be based should reflect large, bulk lot industrial sales.

3. *Contract Rather Than Spot Market Data.*—The Commission proposes that the prices gathered by EIA should be those charged by a seller to a buyer in a contractual type of relationship. There are two reasons for using contract rather than spot market prices. First, spot prices during a given month may not be indicative of the actual prices which large industrial users are paying. It appears on the basis of the information the Commission has before it, that large non-utility industrial users typically purchase a predominant amount of their fuel oil on a contract basis. Second, spot market prices tend, over the long term, to average out at a level near long-term contractual prices. The spot prices may

[5] Section 508(b) of the NGPA vests in the Commission, for purposes of carrying out the functions vested in it by the NGPA, all of the authority vested in the Secretary of Energy by section 301(a) of the DOE Organization Act, which encompasses the authority set forth in section 11(b) of the Energy Supply and Environmental Coordination Act of 1974 and sections 13(b), (c) and (d) of the Federal Energy Administration Act of 1974. This authority will be exercised by the EIA on behalf of the Commission.

[6] It was initially hoped that a data collection effort already in place could be modified to fit the needs of the incremental pricing program, in order to minimize the administrative burden involved in starting the program. The EIA specifically investigated the possibility of using utility purchases of fuel oil as reported on Form EIA-423. EIA concluded, however, that the quality of fuel oil and the terms of purchase encompassed by utility purchases vary significantly from industrial purchases of boiler fuel. In addition, there is no Form EIA-423 data available for No. 6 fuel oil deliveries for 14 states.

at any one time be higher or lower than contract prices, but over any significant length of time, they should approximate, on the average, the contractual prices charged over the same span of time.

4. *Price FOB Buyer's Receiving Terminal.*—Fuel oil sellers would be requested to report to EIA the FOB prices at the purchaser's receiving terminal. Thus, the price data gathered by EIA would reflect transportation costs. This approach was suggested by the majority of the comments received on this issue. Almost all commenters have urged that the alternative fuel price ceilings should reflect the price purchasers pay for the fuel oil delivered to the facility in which the fuel is to be burned.

5. *Before-Tax or After-Tax Data.*—The Commission proposes that all fuel oil prices submitted to EIA be reported exclusive of state and local taxes. The reason for requesting per-tax data and for basing the alternative fuel cost ceilings on such data is that, although the calculation of the incremental pricing surcharge will take into account state and local taxes, the alternative fuel cost ceiling, exclusive of taxes, will have to be known in order to carry out the surcharge calculation. The calculation of incremental pricing surcharges will be discussed in Docket No. RM79-14. The Commission believes the majority of EIA's respondents will be able to report pre-tax prices, since sellers must keep such records for tax purposes and often quote prices exclusive of local taxes.

6. *Conversion Factor.*—Subsection 204(e) requires that the alternative fuel cost by stated on a per million Btu basis. The prices which EIA will collect will typically be on a per barrel basis. Thus, a conversion will be required. The Connecticut Natural Gas Corporation submitted a comment suggesting that adequate provision be made to account for the variations in the Btu content of oils. The EIA has utilized, over time, standard conversion factors of 5.8 million Btu's per barrel of No. 2 fuel oil and 6.3 million Btu's per barrel of No. 6 fuel oil in processing prices of various fuels to place them on a comparable basis. It is anticipated EIA will continue to utilize these factors.

D. *Averaging and Adjustment Methodology*

After EIA collects data on the prices charged for No. 2, No. 6 low sulfur and No. 6 high sulfur fuel oil to industrial users in each of the 39 incremental pricing regions, ceilings will have to be generated from the collected data. The Commission proposes that from the data it collects, EIA derive an average price, weighted by volumes, for each of the three ceiling levels for each region. Once weighted averages have been determined, each average would be adjusted downward by two standard deviations. The point which is two standard deviations removed from the mean would be the ceiling price for incremental pricing purposes unless that point is lower than the lowest reported price for the period. In that event, the lowest reported price would be the ceiling.

The Commission believes the proposed downward adjustment methodology should result in ceiling prices which are close to what the largest industrial users actually pay. If there were no downward adjustment, those industrial boiler fuel facilities which could purchase oil for a price below the weighted average would, absent some unforeseen economic factor, switch to the fuel oil they were capable of burning. The result would be load loss and a shifting of capital costs to high-priority customers.

Under the "two standard deviation" approach, if the price data collected from fuel oil dealers were to form an appoximately normal or "bell" shaped curve, and the ceiling were set at the weighted average minus two standard

deviations, about 2½% of all fuel oil sales would be priced below the ceiling.[6]

There is, however, reason to suspect that the fuel oil price data will not form a normal, "bell" shaped curve. For a variety of reasons having to do with the nature of the fuel oil market, data distributions which are skewed to the right (higher prices) and ending more or less abruptly on the left (lower prices) are likely. The point which is two standard deviations less than the mean of such a distribution may well be below the lowest price reported.[7] It is for this reason the commission proposes to use the higher of the two possible prices—the weighted average adjusted downward by two standard deviations, or the lowest observed price—as the ceiling. If subsequent experience with this approach suggests that the weighted average price need only be adjusted downward by one standard deviation in order to arrive at a price in the vicinity of the lowest actual observed price, the commission will later consider altering the two standard deviation methodology.

Several comments were submitted at the April 2nd conference as to the appropriate adjustment that should be made in deriving a ceiling price from a weighted average. Some comments supported use of fixed percent adjustment factors ranging from 7.5 to 20 percent. An arbitrary percentage adjustment factor would, however, be inflexible. In some cases it would result in a ceiling which would be above a substantial number of observed prices while in other cases it would result in a ceiling below any observed price. Thus, either it would result in fuel switching or it would unnecessarily reduce the flow-through of incremental costs to industrial customers. The approach proposed in this notice attempts to steer between this Scylla and Charybdis.

Several other commenters urged that the ceiling be set at the level of the lowest observed price, with no adjustment. Use of the lowest observed price would insure to a large extent against loss of load, but, if the lowest observed price were atypical, could reduce significantly and unnecessarily the amount of incremental costs which could be passed through to industrial users.

E. *Frequency of Data Collection and Publication*

The Commission proposes to request EIA to collect data and to publish alternative fuel price ceilings each month. This reflects the view expressed by many of the participants in the April 2nd conference. The Commission is concerned about the administrative burden involved with a monthly collection and publication schedule. However, the Commission is currently disposed to accept the counsel of those comments expressing the view that oil prices are changing so rapidly that anything less frequent than monthly publication of ceiling prices would be inadequate.

On the one hand, in a period of rising oil prices, a certain proportion of the costs which industrial users could bear would not be directed to them if alternate fuel ceilings were established on a less frequent basis. On the other hand, if there were falling prices due, perhaps, to undercutting of the ceiling

[6] A standard deviation is a statistical measure of the degree of dispersion, or scatter, in a sample of data which has been gathered at random. The greater the degree of dispersion, the greater the value of the standard deviation. The probability that any single observation in a large set of randomly selected observations will lie far from the average is mathematically described in terms of the standard deviation. For example, if a set of data is distributed according to a "bell" shaped curve, approximately 68% of all observations will differ from the average by less than one standard deviation. Approximately 95% of the observations will differ from the average by less than two standard deviations. In this latter case, generally half of the outlying observations, or about 2½% of the total, will be on the low side. Thus, while 50% of all observations can be expected to be lower than the average, only about 2½% can be expected to be lower than the average minus two standard deviations.

[7] Commissioner Robert Fischbach of North Carolina submitted data for a recent month indicating that the lowest price being paid in that state by an industrial user for No. 6 fuel oil is approximately 1.6 standard deviations below the weighted average price paid by the North Carolina state government for No. 6 oil.

by fuel oil dealers, less frequent publication would probably result in fuel switching.

Several commenters expressed their concern that fuel oil dealers may be tempted to undercut the alternative fuel price ceilings established in any given period in order to lure possible customers to fuel oil. Establishment of alternative fuel price ceilings on a monthly basis should discourage undercutting. If fuel oil dealers cut their prices in one month, the ceiling prices would soon decrease also, since the ceiling prices will be based on fuel oil prices actually charged. If the undercutting were to continue, the ceiling prices would quickly reach a level where further undercutting would be uneconomical for fuel dealers.

The Commission believes that any lag between the collection of data and the publication of ceiling prices based thereon should be minimized. EIA has informed the Commission that the collection and analysis of data for any given month will require approximately 45 days of processing time. On the other hand, however, ceiling prices should be available to the public at least 15 days before they are to be utilized. Accordingly, the Commission proposes to request EIA to publish ceiling prices within 45 days after the close of the month for which data is collected, but no later than 15 days prior to the first day of he month for which the ceiling prices would be applicable. Thus, data collected for October, 1979 would have to be published in the form of ceiling prices by December 14, 1979. (December 15, 1979, falls on a weekend.) The ceiling prices would be published in the Federal Register and would be available through the FERC Office of Public Information.

The Commission is aware that, at least in part, prices for heavy oils have fluctuated seasonally. Prices for heavy oils usually decline in the summer months and begin to rise in late summer and early fall. This phenomenon, if it were to occur, could create problems. April fuel oil prices will, for example, form the basis of ceilings for July. By then, industrial users might be able to purchase fuel oil at a lower cost. The Commission specifically requests comments as to whether, and to what extent, there is a seasonality problem; whether the proposed "two-standard deviation" downward adjustment method will adequately compensate for this seasonality problem; and whether any additional adjustments will be required. If any commenters urge that there should be some additional adjustment to compensate for seasonal fluctuations in oil prices they should describe with specificity the sort of adjustment method they would propose.

IV. Comments Requested.

The Commission requests comments on the proposed regulations set forth below. In particular, the Commission requests comments on whether the proposals are workable, whether they will serve to fully implement the alternative fuel cost ceiling provisions of Title II of the NGPA, and the nature and significance of any environmental issues. Any person who believes an approach other than that described in this Notice would provide a more workable and appropriate regulatory approach to implement section 204(e) of the NGPA is encouraged to submit suggestions in detail.

The Commission also requests the submission of any studies, data or statistical analyses that will enable it to thoroughly evaluate the various alternatives described above and as may be submitted by commenters.

V. Comment Procedures

A. *Written Comments.*—Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79–21. An original and 14 copies should be filed.

All comments received prior to 4:30 p.m. EDT, June 19, 1979, will be considered by the Commission to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

B. *Public Hearings.*—Public hearings concerning this proposal will be held in St. Paul, Minnesota on June 6, 1979; in Los Angeles, California on June 8, 1979; in Atlanta, Georgia on June 15, 1979; and in Washington, D.C. on June 18, 1979. The times and places for the hearings are indicated in the "DATES" and "ADDRESSES" section of this Notice. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at any of the hearings provided that a written request to participate is submitted to the Secretary of the Commission at the address given above at least seven days before the date the hearing is to be convened. Requests to participate should include a reference to Docket No. RM79–21, should indicate the hearing in which the person making the request wishes to participate, should indicate the amount of time desired, and should include a telephone number where the person making the request may be reached. A list of the participants in each hearing will be available in the Commission's Office of Public Information three days before the hearing and will be available at the site of the hearing on the morning of the hearing. The presiding officer is authorized to limit oral presentations at the public hearings both as to length and as to substance. Persons participating in the public hearings should, if possible, bring 150 copies of their testimony to the hearings.

The hearings will not be judicial or evidentiary-type hearings. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearings. Transcripts of the hearings will be available in the public file for this proceeding, Docket No. RM79–21, in the Commission's Office of Public Information.

The Commission proposes to make these amendments, when adopted, effective on September 1, 1979. As noted above, Title II of the NGPA requires that final regulations be in place by November 9, 1979. In order that both the regulations set forth below and the regulations to be adopted in Docket No. RM79–14 can be implemented with the least disruption to currently followed reporting and accounting practices, the Commission proposes to adopt these regulations prior to the November 9th deadline.

(Natural Gas Act as amended, 15 U.S.C. 17 *et seq.;* the Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.;* the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.;* E.O. 12009, 42 FR 46267)

In consideration of the foregoing, it is proposed to amend Subchapter I of Chapter I of Title 18 of the Code of Federal Regulations by the addition of a new Part 282, to read, in part, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

Subchapter I of Chapter I of Title 18 is amended by adding a new Part 282 to read as follows:

PART 282—INCREMENTAL PRICING

Subpart A—General Rules and Definitions

Sec.

282.101 Purpose.
282.102 Applicability and effective date.
282.103 Definitions.

Subpart B [Reserved]

Subpart C [Reserved]

Subpart D—Alternative Fuel Cost

282.401 Scope.
282.402 General rule.
282.403 Alternative fuel capability of a facility.
282.404 Alternative fuel price ceilings.

Subpart E [Reserved]

Subpart F [Reserved]

Appendix

Authority: This part is issued under the Natural Gas Act as amended, 15 U.S.C. 717 *et seq.*; the Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*; the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267.

Subpart A—General Rules and Definitions

§ 282.101 Purpose.

The purpose of this part is to set forth an incremental pricing rule in accordance with Title II of the Natural Gas Policy Act of 1978. The rule requires that certain costs of acquiring natural gas be passed through as a surcharge on sales of natural gas used for certain uses specified in the rule.

§ 282.102 Applicability and effective date.

(a) *Costs.* Costs described in Subpart —— and incurred by natural gas suppliers on or after January 1, 1980 shall be subject to this part.

(b) *Natural gas suppliers.* Interstate pipelines and local distribution companies shall be subject to this part.

(c) *Effective date.* The provisions of this part shall be effective September 1, 1979.

§ 282.103 Definitions.

For purposes of this part: (a) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(b) "Industrial facility" means any facility which primarily changes raw or unfinished materials into another form or product.

(c) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the provisions of this part in accordance with § ——.

(d) "No. 2 fuel oil" means No. 2 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(e) "No. 6 fuel oil" means No. 6 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(f) "Low sulfur fuel oil" means any oil containing 1 percent (1%) or less sulfur content by weight.

(g) "High sulfur fuel oil" means any oil containing more than 1 percent (1%) sulfur content by weight.

Subpart B [Reserved]

Subpart C [Reserved]

Subpart D—Alternative Fuel Cost

§ 282.410 Scope.

This subpart implements section 204(e) of the NGPA and sets forth the method of determination of the alternative fuel price ceiling to be used in the calculation of the incremental pricing surcharge to industrial users.

§ 282.402 General Rule.

(a) The alternative fuel capability of each non-exempt industrial boiler fuel facility shall be determined as described in § 282.403.

(b)(1) Alternative fuel price ceilings shall be determined for No. 2 fuel oil, No. 6 low sulfur fuel oil, and No. 6 high sulfur fuel oil for each incremental pricing region in the manner described in § 282.404.

(2) The alternative fuel price ceiling which shall be applicable to a non-exempt industrial boiler fuel facility for incremental pricing purposes during any month shall be the ceiling which has been established for that month for the region in which the facility is located and which corresponds to the lowest-priced alternative fuel capability of the facility as determined in accordance with § 280.403.

§ 282.403 Alternative fuel capability of a facility.

(a) *General rule.* Each non-exempt industrial boiler fuel facility subject to this part shall, for purposes of this part, be deemed to have the capability to use No. 2 fuel oil as an alternative to natural gas, except for those facilities which are certified as having the capability to burn No. 6 high sulfur fuel oil or No. 6 low sulfur fuel oil, as provided by paragraph (b) of this section. Such certification shall be made by filing an alternative fuel capability form as provided in paragraph (c) of this section.

(b) *Certification of No. 6 capability.* A responsible official associated with a non-exempt industrial boiler fuel facility:

(1) may certify that the facility has the capability to burn No. 6 high sulfur fuel oil if the facility is technically capable and legally permitted to burn No. 6 high sulfur fuel oil; or

(2) may certify that the facility has the capability to burn No. 6 low sulfur fuel if the facility is technically capable and legally permitted to burn No. 6 low sulfur fuel oil.

(c) *Alternative fuel capability form.* (1) *Commission to provide form.* The Commission shall provide the alternative fuel capability form referenced in paragraph (a) to be used in the certification of the alternative fuel capabilities of non-exempt industrial boiler fuel facilities.

(2) *Commission address.* Alternative fuel capability forms will be available upon request from the Office of ————, Federal Energy Regulatory Commission, Room ———, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(3) *Forms available from natural gas suppliers.* Natural gas suppliers shall make available for the use of their customers copies of the FERC alternative fuel capability form.

(i) *Initial service of form.* Not later than September 1, 1979, each natural gas supplier shall mail or otherwise supply an alternative fuel capability form to each facility on each natural gas supplier's system which the natural gas supplier did not determine to be exempt from incremental pricing on the basis of the natural gas supplier's own records.

(ii) *Ongoing availability of form.* After September 1, 1979, natural gas suppliers shall make alternative fuel capability forms available at their principal place of business on an ongoing basis during regular business hours.

(4) *Contents of form.* The alternative fuel capability form shall: (i) provide the affiant the opportunity to certify that its industrial boiler fuel facility is technically capable and legally permitted to burn No. 6 low sulfur fuel oil;

(ii) provide the affiant the opportunity to certify that its industrial boiler fuel facility is technically capable and legally permitted to burn No. 6 high sulfur fuel oil;

(iii) notify the affiant that its industrial boiler fuel facility will be subject to an alternative fuel price ceiling corresponding to the level of the alternative fuel capability certified by the affiant;

(iv) contain a provision placing the affiant on notice that if a certification is made that an industrial boiler fuel facility is technically capable and legally permitted to burn a No. 6 fuel oil, records substantiating such certification must be retained, as provided in paragraph (g) of this section; and

(v) require the affiant, either on the form or in an attachment to the form, to describe the records which will be retained.

(5) *Filing.* A certification of alternative fuel capability shall be effective only after an alternative fuel capability form is completed, signed and dated under oath, and filed with the Office of ————, Federal Energy Regulatory Commission, Room ———, 825 North Capitol Street, N.E., Washington, D.C. 20426, with a copy sent to the natural gas supplier serving the facility.

(d) *Effective date of certification.* A properly executed and filed alternative fuel capability form shall determine the

alternative fuel price ceiling which shall be applicable to a facility as of the beginning of the first full month of service after the form is filed with the Commission and received by the facility's natural gas supplier.

(e) *Public availability of certification.* (1) A natural gas supplier shall maintain at its principal place of business copies of all alternative fuel capability forms which it has received and make such copies available for public inspection during regular business hours.

(2) Copies of alternative fuel capability forms filed with the Commission shall be available through the Office of Public Information, Room 1000, Federal Energy Regulatory Commission, 825 North Capitol Street, Washington, D.C. 20426. A copy of the alternative fuel capability form filed by any particular industrial user will be mailed to any interested party who requests it.

(f) *Protests.* Any interested person who desires to protest the alternative fuel capability claimed on an alternative fuel capability form may file a protest. The procedures set forth in § 1.10 shall govern the filing of such a protest.

(g) *Record retention.* (1) Each industrial user shall maintain books and records to substantiate a certification of alternate fuel capability under this section. Such books and records shall be retained for a period of three years following the initial billing by the natural gas supplier which reflects the alternate fuel capability which has been certified.

(2) Each industrial user shall make such books and records available during regular business hours for public inspection in a convenient form and place.

282.404 Alternative fuel price ceilings.

(a) *General rule.* Each month, for each region as set forth in paragraph (b) of this section, three alternative fuel price ceilings on incremental pricing shall be established. These ceilings shall be based on the prices paid in each such region by industrial users for No. 2 fuel oil, No. 6 low sulfur fuel oil and No. 6 high sulfur fuel oil. Such price data shall be gathered in accordance with paragraph (c) of this section and shall be derived from that data in accordance with paragraph (d) of this section. Alternative fuel price ceilings shall be published in accordance with paragraph (e) of this section.

(b) *Incremental pricing regions.* Alternative fuel price ceilings shall be established for each of the 39 regions described and indicated in the Appendix to this part.

(c) *Data from which alternative fuel price ceilings will be determined.* Each month, data shall be collected on the prices being charged for No. 2 fuel oil, No. 6 high sulfur fuel oil and No. 6 low sulfur fuel oil to industrial users located in each incremental pricing region. Such data shall be collected from fuel oil sellers. The prices collected shall be those that are charged for volumes delivered to large, non-utility industrial users which purchase on a large lot or contract basis and shall not include state or local sales taxes.

(d) *Method for deriving alternative fuel price ceilings.* (1) Based on the data described in paragraph (c) of this section, an average price, weighted by volumes, shall be calculated for each of the three alternative fuels for each region.

(2) Weighted average prices shall be adjusted downward by two standard deviations.

(3) For each region, the weighted average price for each fuel, as adjusted, shall be compared to the lowest reported actual price for such fuel. The higher of these shall be established as the alternative fuel price ceiling for that fuel for the region.

(e) *Publication of ceilings.* (1) Alternative fuel price ceilings shall be made public no later than fifteen days prior to the first day of the calendar month during which such ceilings will be used for incremental pricing under this part.

(2) The alternative fuel price ceilings published in December, 1979, for the month of January, 1980, shall be based on data reported for October, 1979 sales.

Ceilings published in following months shall be similarly based on data gathered for the second month previous to the month in which the ceiling is published.

Subpart E [Reserved]

Subpart F [Reserved]

Appendix

Region 1.—Boston-Lawrence-Lowell, Mass.-N.H. Metropolitan Area.
(Associated with Region 32.)
Counties: Essex, Mass., Middlesex, Mass., Norfolk, Mass., Plymouth, Mass., Suffolk, Mass., Rockingham, N.H.
Region 2.—Hartford-New Britain-Bristol, Ct. Metropolitan Area.
(Associated with Region 32.)
Counties: Hartford, Ct., Middlesex, Ct., Tolland, Ct.
Region 3.—New York-Newark-Jersey City, N.Y., N.J., Ct. Metropolitan Area.
(Associated with Region 33.)
Cities: New York City.
Counties: Putnam, N.Y., Rockland, N.Y., Westchester, N.Y., Bergen, N.J., Essex, N.J., Morris, N.J., Somerset, N.J., Union, N.J., Hudson, N.J., Nassau, N.Y., Suffolk, N.Y., Monmouth, N.J., Middlesex, N.J., Passaic, N.J., Fairfield, Ct.
Region 4.—Philadelphia-Wilmington-Trenton, Pa., Del., Md., N.J. Metropolitan Area.
(Associated with Region 33.)
Counties: Bucks, Pa., Chester, Pa., Delaware, Pa., Montgomery, Pa., Philadelphia, Pa., Burlington, N.J., Camden, N.J., Gloucester, N.J., Mercer, N.J., New Castle, Del., Salem, N.J., Cecil, Md.
Region 5.—Baltimore, Md. Metropolitan Area.
(Associated with Region 33.)
Cities: Baltimore, Md.
Counties: Anne Arundel, Md., Baltimore, Md., Carroll, Md., Harford, Md., Howard, Md.
Region 6.—Washington, D.C., Md., Va. Metropolitan Area.
(Associated with Region 33.)
Cities: District of Columbia, Alexandria, Va., Fairfax, Va., Falls Church, Va., Manassas, Va., Manassas Park, Va.
Counties: Charles, Md., Montgomery, Md., Prince George's, Md., Arlington, Va., Fairfax, Va., Loudoun, Va., Prince William, Va.
Region 7.—Atlanta, Ga. Metropolitan Area.
(Associated with Region 34.)
Counties: Butts, Ga., Cherokee, Ga., Clayton, Ga., Cobb, Ga., DeKalb, Ga., Douglas, Ga., Fayette, Ga., Forsyth, Ga., Fulton, Ga., Gwinnett, Ga., Henry, Ga., Newton, Ga., Paulding, Ga., Rockdale, Ga., Walton, Ga.
Region 8.—Tampa-St. Petersburg, Fla. Metropolitan Area.
(Associated with Region 34.)
Counties: Hillsborough, Fla., Pasco, Fla., Pinellas, Fla.
Region 9.—Miami-Fort Lauderdale, Fla. Metropolitan Area.
(Associated with Region 34.)
Counties: Broward, Fla., Dade, Fla.
Region 10.—Buffalo, N.Y. Metropolitan Area.
(Associated with Region 33.)
Counties: Erie, N.Y., Niagara, N.Y.
Region 11.—Pittsburgh, Pa. Metropolitan Area.
(Associated with Region 33.)
Counties: Allegheny, Pa., Beaver, Pa., Washington, Pa., Westmoreland, Pa.
Region 12.—Detroit-Ann Arbor, Mich. Metropolitan Area.
(Associated with Region 35.)
Counties: Lapeer, Mich., Livingston, Mich., Macomb, Mich., Oaklawn, Mich., St. Claire, Mich., Wayne, Mich., Washtenaw, Mich.
Region 13.—Cleveland-Akron-Lorain, Ohio Metropolitan Area.
(Associated with Region 35.)
Counties: Cuyahoga, Oh., Geauga, Oh., Lake, Oh., Medina, Oh., Portage, Oh., Summit, Oh., Lorain, Oh.
Region 14.—Columbus, Oh. Metropolitan Area.
(Associated with Region 35.)
Counties: Delaware, Oh., Fairfield, Oh., Franklin, Oh., Madison, Oh., Pickaway, Oh.
Region 15.—Cincinnati-Hamilton, Ohio-Ky.-Ind. Metropolitan Area.
(Associated with Region 35.)
Counties: Clermont, Oh., Hamilton, Oh., Warren, Oh., Boone, Ky., Campbell, Ky., Kenton, Ky., Dearborn, Ind., Butler, Oh.
Region 16.—Indianapolis, Ind. Metropolitan Area.
(Associated with Region 35.)
Counties: Boone, Ind., Hamilton, Ind., Hancock, Ind., Hendricks, Ind., Johnson, Ind., Marion, Ind., Morgan, Ind., Shelby, Ind.
Region 17.—New Orleans, La. Metropolitan Area.
(Associated with Region 37.)
Parishes: Jefferson, La., Orleans, La., St. Bernard, La., St. Tammany, La.
Region 18.—Milwaukee-Racine, Wis. Metropolitan Area.
(Associated with Region 35.)
Counties: Milwaukee, Wis., Ozaukee, Wis., Washington, Wis., Waukesha, Wis., Racine, Wis.

Region 19.—Chicago-Gary, Ill.-Ind. Metropolitan Area.
(Associated with Region 35.)
Counties: Cook, Ill., Du Page, Ill., Kane, Ill., Lake, Ill., McHenry, Ill., Will, Ill., Lake, Ind., Porter, Ind.

Region 20.—St. Louis, Mo.-Ill. Metropolitan Area.
(Associated with Region 36.)
Cities: St. Louis, Mo.
Counties: Franklin, Mo., Jefferson, Mo., St. Charles, Mo., St. Louis, Mo., Clinton, Ill., Madison, Ill., Monroe, Ill., St. Clair, Ill.

Region 21.—Houston-Galveston, Tx. Metropolitan Area.
(Associated with Region 37.)
Counties: Brazoria, Tx., Fort Bend, Tx., Harris, Tx., Liberty, Tx., Montgomery, Tx., Waller, Tx., Galveston, Tx.

Region 22.—Minneapolis-St. Paul, Minn.,-Wis. Metropolitan Area.
(Associated with Region 36.)
Counties: Anoka, Mn., Carver, Mn., Chisago, Mn., Dakota, Mn., Hennepin, Mn., Ramsey, Mn., Scott, Mn., Washington, Mn., Wright, Mn., St. Croix, Wis.

Region 23.—Kansas City, Mo.-Kan. Metropolitan Area.
(Associated with Region 36.)
Counties: Cass, Mo., Clay, Mo., Jackson, Mo., Platte, Mo., Ray, Mo., Johnson, Kan., Wyandotte, Kan.

Region 24.—Dallas-Fort Worth, Tx. Metropolitan Area.
(Associated with Region 37.)
Counties: Collin, Tx., Dallas, Tx., Denton, Tx., Ellis, Tx., Hood, Tx., Johnson, Tx., Kaufaman, Tx., Parker, Tx., Rockwall, Tx., Tarrant, Tx., Wise, Tx.

Region 25.—Denver-Boulder, Col. Metropolitan Area.
(Associated with Region 38.)
Counties: Adams, Col., Arapahoe, Co., Boulder, Col., Denver, Col., Douglas, Col., Gilpin, Col., Jefferson, Col.

Region 26.—Phoenix, AZ. Metropolitan Area.
(Associated with Region 39.)
Counties: Maricopa, Az.

Region 27.—Los Angeles-Long Beach-Anaheim, Ca. Metropolitan Area.
(Associated with Region 39.)
Counties: Los Angeles, Ca., Orange, Ca., Ventura, Ca., Riverside, Ca., San Bernardino, Ca.

Region 28.—San Diego, Ca. Metropolitan Area.
(Associated with Region 39.)
Counties: San Diego, Ca.

Region 29.—Seattle-Takoma, Wash. Metropolitan Area.
(Associated with Region 39.)
Counties: King, Wash., Spohomish, Wash., Pierce, Wasn.

Region 30.—Portland, Or.-Wash. Metropolitan Area.
(Associated with Region 39.)
Counties: Clackamas, Or., Multnomah, Or., Washington, Or., Clark, Wash.

Region 31.—San Francisco-Oakland-San Jose, Ca. Metropolitan Area.
(Associated with Region 39.)
Counties: Alameda, Ca., Contra Costa, Ca., Merin, Ca., San Francisco, Ca., San Mateo, Ca., Santa Clara, Ca., Napa, Ca., Solano, Ca.

Region 32.—New England Multistate Region.
Maine
New Hampshire excluding: Rockingham County.
Vermont.
Massachusetts excluding: Essex, Middlesex, Norfolk, Plymouth and Suffolk Counties.
Connecticut excluding: Hartford, Middlesex, Tolland and Fairfield Counties.
Rhode Island.

Region 33.—Mid-Atlantic Multistate Region.
New York excluding: Putnam, Rockland, Westchester, Nassau, Suffolk, Erie and Niagara Counties, New York City.
Pennsylvania excluding: Bucks, Chester, Delaware, Montgomery, Philadelphia, Allegheny, Beaver, Washington, and Westmoreland Counties.
New Jersey excluding: Bergen, Essex, Morris, Somerset, Union, Hudson, Monmouth, Middlesex, Passaic, Burlington, Camden, Gloucester, Mercer and Salem Counties.
Delaware excluding: New Castle County.
Maryland excluding: Cecil, Charles, Montgomery, Prince George's, Anne Arundel, Baltimore, Carroll, Harford, and Howard Counties, Baltimore City.

Region 34.—Southern Multistate Region.
Virginia excluding: Arlington, Fairfax, Loudoun and Prince William Counties, Alexandria, Fairfax, Falls Church, Manassas, and Manassas Park Cities.
North Carolina, South Carolina, Tennessee.
Georgia excluding: Butts, Cherokee, Clayton, Cobb, DeKalb, Douglas, Fayette, Forsyth, Fulton, Gwinnett, Henry, Newton, Paulding, Rockdale, and Walton Counties.
Broward, Dade, Hillsborough, Pasco, and Pinellas Counties.
Alabama, Mississippi.

Region 35.—Mid Western Multistate Region.
West Virginia.
Kentucky excluding: Boone, Campbell, and Kenton Counties.
Ohio excluding: Cuyahoga, Geauga, Lake, Medina, Portage, Summit, Lorain, Clermont, Hamilton, Warren, Butler, Delaware, Fairfield, Franklin, Madison and Pickaway Counties.
Indiana excluding: Lake, Porter, Dearborn, Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan and Shelby Counties.
Michigan excluding: Lapeer, Livingston, Macomb, Oakland, St. Clair, Wayne and Washtenaw Counties.
Illinois excluding: Cook, Du Page, Kane, Lake, McHenry, Will, Clinton, Madison, Monroe, and St. Clair Counties.
Wisconsin excluding: Milwaukee, Ozaukee, Washington, Waukesha, Racine, and St. Croix Counties.
Region 36.—Plains States Multistate Region.
Minnesota excluding: Anoka, Carver, Chisago, Dakota, Hennepin, Ramsey, Scott, Washington, and Wright Counties.
Iowa.
Missouri excluding: St. Louis City, Franklin, Jefferson, St. Charles, St. Louis, Cass, Clay, Jackson, Platte, and Ray Counties.
Kansas excluding: Johnson and Wyandotte Counties.
Nebraska.
North Dakota.
South Dakota.

Region 37.—South Central Multistate Region.
Arkansas.
Louisiana excluding: Jefferson, Orleans, St. Bernard and St. Tammany Parishes.
Texas excluding: Collin, Dallas, Denton, Ellis, Hood, Johnson, Kaufman, Parker, Rockwall Tarrant, Wise, Brazoria, Fort Bend, Harris, Liberty, Montgomery, Waller, and Galveston Counties.
Oklahoma.
New Mexico.

Region 38.—Rocky Mountain Multistate Region.
Montana.
Idaho.
Wyoming.
Utah.
Colorado excluding: Arapahoe, Boulder, Denver, Douglas, Gilpin, Jefferson, and Adams Counties.

Region 39.—Pacific Coast Multistate Region.
Washington excluding: King, Snohomish, Pierce and Clark Counties.
Oregon excluding: Clackamas, Multnomah, and Washington Counties.
Nevada.
California excluding: Los Angeles, Orange, Ventura, Riverside, San Bernardino, Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, Napa, Solano, and San Diego Counties.
Arizona excluding: Maricopa County.

[FR Doc. 79-15477 Filed 5-17-79; 8:45 am]

¶ 32,024 Assessment of Penalties for Knowing Violations of the Natural Gas Policy Act

Note: This proposed rulemaking has been withdrawn and the docket number terminated. (45 *Federal Register* 56073, August 22, 1980).

44 F. R. 29101 (May 18, 1979)

[18 CFR Part 286]

[Docket No. RM79-42]

Proposed Rulemaking under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Natural Gas Policy Act of 1978 authorizes the Commission to assess civil penalties for knowing violations of the Act or of rules and orders issued thereunder. To clarify the procedures to apply in such instances the Commission proposes to adopt the rules set forth herein.

DATES: Comments by June 18, 1979; hearing on June 22, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM79-42)

FOR FURTHER INFORMATION CONTACT:

Philip M. Marston, Office of Enforcement, Federal Energy Regulatory Commission, 941 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-0303; or

Stephen R. Melton, Office of Enforcement, Federal Energy Regulatory Commission, 941 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-4040.

SUPPLEMENTARY INFORMATION:

I. Background

Section 504(b)(6) of the Natural Gas Policy Act of 1978 (NGPA) authorizes the Commission to assess civil penalties of up to $5,000 for knowing violations of the NGPA or of rules and orders issued thereunder. To clarify the procedures to apply in such instances, the Commission proposes to establish procedures to govern the assessment of civil penalties under the NGPA.

II. Summary Of The Proposal

The proposed regulation would add a new § 286.103 to Part 286 of the Commission's regulations. Under the procedures, the Commission would initiate a civil penalty proceeding by issuing and serving upon the alleged violator a notice of the proposed assessment order naming respondent, describing briefly the violations for which the penalty is assessed, and fixing the amount of penalty to be paid within 60 days following receipt of the order.

The notice would also inform the respondent that he may submit factual information or legal arguments to the Commission within 30 days following receipt of the notice. In the submission, respondent may attempt to show, for example, why no penalty should be imposed or why the amount of the penalty should be reduced.

Within 30 days after receiving the respondent's submission, the Commission will act either by issuing an assessment order or by concluding that no further action on the notice will be taken.

If the penalty has not been paid within 60 days following receipt of the notice and order, the Commission could institute an enforcement action in an appropriate federal district court for an order affirming and enforcing the penalty assessment. Section 504(b)(6)(F) of the NGPA provides that in such an enforcement action the court shall have authority to conduct a *de novo* review of both the law and the facts. Accordingly, the proposal's summary procedures for initiating the process at the administrative level provide respondents an adequate opportunity to participate.

III. Written Comment Procedures

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to June 18, 1979 will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street NE., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM79–42

IV. Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on June 22, 1979 beginning at 10:00 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on June 18, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM79–42 as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m., on June 18, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 10 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons, and any interested person may submit questions to the presiding officer to be asked of persons making statements. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3340, 15 U.S.C. § 3301 *et seq.*; Department of Energy Organization Act, Pub. L. 95–91, 91 Stat. 565, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, the Commission proposes to amend Part 286, Subchapter I, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

Part 286, Subchapter I, Chapter I of Title 18, Code of Federal Regulations, is amended by adding a new § 286.103 to read as follows:

* * * * *

§ 286.103 Assessment of civil penalties.

(a) *Scope.* This section applies to proceedings for the assessment of civil penalties pursuant to Section 504(b)(6) of the NGPA.

(b) *Penalties.* The Commission may assess a civil penalty of not more than $5,000 for any one violation against any person whom the Commission determines to have knowingly violated any provision of the NGPA or any provision of any rule or order of the Commission issued under the NGPA. In

the case of a continuing violation, each day of violation shall constitute a separate violation.

(c) *Assessment procedure.*

(1) *Notice of assessment.* When the commission determines on the basis of information available to it that knowing violations have occurred or are occurring and that the imposition of civil penalties is appropriate, the Commission shall initiate assessment proceedings by issuing and serving upon the alleged violator a notice of the proposed penalty naming such person as respondent, setting forth the violations for which the penalty is to be assessed, and fixing the amount of the penalty. The notice shall also inform the respondent that he may, within 30 days following receipt of the notice submit factual information or legal arguments bearing on alleged liability or on the appropriate amount of the penalty to be assessed.

(2) *Assessment order.* Within 30 days following receipt of the respondent's submission, if any, the Commission shall issue and serve upon the respondent an assessment order or shall determine that no further action will be taken. The assessment order shall set forth the violations for which the penalty is assessed, fix the amount of the penalty assessment, and direct the respondent to pay the assessment within 60 days of the date the order issues.

(d) *Failure to pay.* If respondent has not paid the assessment within 60 days following receipt of the notice and order, the Commission may institue an action in the appropriate federal district court for an order affirming and enforcing the penalty assessment.

¶ 32,025 Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

44 F. R. 33099 (June 8, 1979).

[18 CFR Parts 154, 201, 204 and 282]

[Docket No. RM79-14]

Proposed Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

Issued June 5, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking and Opportunity for Written and Oral Presentations of Data, Views, and Arguments.

SUMMARY: The Federal Energy Regulatory Commission (FERC) hereby gives notice of a proposed rulemaking and public hearing for the purpose of implementing the incremental pricing provisions of the Natural Gas Policy Act of 1978. The regulations included in this proposal provide the regulatory framework for the calculation and billing of incremental pricing surcharges to non-exempt industrial boiler fuel facilities. The proposed regulations also set forth the procedures by which an industrial facility may obtain an exemption from the incremental pricing program.

DATES: Comments by July 9, 1979. Requests to speak by June 22, 1979. Hearing date: June 27, 1979, 10:00 a.m.

ADDRESSES: All comments and requests to speak to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM79-14). *Hearing Location:* Federal Energy Regulatory Commission, Hearing Room A, 825 North Capitol Street, NE., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Norman A. Pedersen, Office of Commissioner George R. Hall, 825 North Capitol Street NE., Room 9006, Washington, D.C. 20426, (202) 275-4147.

Warren C. Edmunds, Office of Pipeline and Producer Regulations, 825 North Capitol Street NE., Room 7303, Washington, D.C. 20426, (202) 275-4415.

Nancy E. Williams, Office of General Counsel, 825 North Capitol Street NE., Room 8100 F, Washington, D.C. 20426, (202) 275-0422.

Notice of Proposed Rulemaking and Opportunity for Written and Oral Presentations of Data, Views, and Arguments—Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that interstate pipelines and local distribution companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of surcharges. These surcharges may not, however, raise the ultimate cost of gas to the user above the cost of the fuel oil which could be used as an alternative to natural gas.

The incremental pricing program is to be implemented in two phases. The only facilities affected during the first phase will be those using natural gas as fuel for large industrial boilers. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979.

During the second phase of the program, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The regulations implementing the second phase must be promulgated by May 9, 1980 and will be subject to Congressional review.

The Commission has determined that the regulations needed to implement the first phase of incremental pricing should be promulgated in two rulemaking

dockets, Docket Nos. RM79-14 and RM79-21. Informal public conferences in these two dockets were held in February and April, 1979, to assist the Commission in the implementation of the incremental pricing program.

A Notice of Proposed Rulemaking and Opportunity for Written and Oral Presentations of Data, Views and Arguments was issued in Docket No. RM79-21 on May 11, 1979 (44 FR 29090, May 18, 1979). The Notice set forth proposed regulations for the determination of the alternative fuel price ceilings on incremental pricing surcharges. Public hearings on the proposal contained in the May 11th Notice will be held in several cities during the month of June.

The proposal contained in this Notice is intended to implement the provisions of Title II which were not addressed in the May 11th Notice in Docket No. RM79-21. Briefly, the regulations set forth below contain the regulatory provisions governing the actual calculation and billing of incremental pricing surcharges, as well as the accounting provisions necessary for the successful implementation of the program. Additionally, the proposed regulations establish procedures by which facilities can obtain exemptions from incremental pricing.

The regulatory set forth below are quite detailed. This preamble will highlight certain issues which received significant attention in the course of the informal conferences held in this docket in February and April.

The Commission has utilized a number of ideas from various proposals offered at the conferences. The Commission would again like to express its appreciation to all those who participated in the conferences. The discussions which took place were invaluable in the formulation of the proposals in this docket and in Docket No. RM79-21.

II. The Proposed Mechanism: The Reducing PGA Approach

The February, 1979 informal conference was called to discuss a proposal developed by Commission staff for the calculation and billing of the incremental pricing surcharges. That proposal was included in the January 12, 1979, Notice (44 FR 6133, January 31, 1979) convening the February conference.

The January proposal was criticized at the conference because, under it, incremental pricing surcharges would not be billed until 4 to 10 months after the actual incurrence of the costs which are to be passed through by way of surcharges. This would result in high carrying costs which would ultimately be borne by high-priority users as well as industrial users.

Several alternative proposals for the calculation and billing of incremental pricing surcharges were proposed at the February conference. The April conference in this docket was convened to discuss those proposals in more detail. The incremental pricing mechanism contained in the regulations set forth below is based on an approach suggested at the April conference by the United Distribution Companies (UDC), Northern Natural Gas Company (Northern) and Natural Gas Pipeline Company of America (Natural).

Under this approach, each interstate pipeline company which files purchased gas adjustment (PGA) rate changes would, prior to each PGA period, project its total gas acquisition costs for the period. That total would be reduced by the amount which the pipeline projects it will recover during the period through incremental pricing surcharges. The total projected gas acquisition cost, as reduced, would be used to derive the pipeline's PGA rate for the PGA period in the manner prescribed in the pipeline's PGA provision.

In order to project the costs which will be recovered through incremental pricing surchanges during a forthcoming PGA period, an interstate pipeline would estimate both the amount of incremental gas acquisition costs it would incur during the period and the proportion of those costs which it could pass through to non-exempt industrial

boiler fuel users in the form of incremental pricing surcharges.

For purposes of computing the projected gas acquisition costs, the Commission proposes to amend its current regulations to allow purchasers to take into account increased costs which are anticipated due to calling price increases permitted under the NGPA ceiling price regulations.

The estimation of the costs which could be passed through as incremental pricing surchanges would be derived from projections of the maximum surcharge absorption capability ("MSAC") of each non-exempt industrial boiler fuel facility ultimately served by the pipeline, either through direct sales or through sales-for-resale. Each natural gas supplier would estimate the MSAC of each industrial facility it serves directly, following the formula set forth in the regulations. The supplier would then determine, for each of the pipelines supplying it, its capability to absorb a surcharge from the pipeline and would report its surcharge absorption capability to the pipeline. This reporting would continue along a chain or resales until the most "upsteam" supplying pipeline had received reports from all of its customers.

That pipeline would add to the total MSAC reported to it the projected MSAC for its own direct sales. This total would then be compared to the pipeline's estimated incremental acquisition costs for the coming PGA period. The lesser figure would be used to reduce the total acquisition costs which the pipeline would otherwise include in its PGA filing with the Commission.

The reduced PGA rate of a pipeline would be used during the succeeding PGA period. Each month of the PGA period, the pipeline's customers would be billed this reduced PGA rate as well as an incremental pricing surcharge.

Surcharges would be based on actual usage, actual rates and actual alternative fuel price ceilings established for the month in question.

The incremental pricing surcharge which would be collected by a pipeline from each of its sale for resale customers would be the MSAC of the sale for resale customer for the previous month, as reported by the customer, or, if less than the MSAC, the customer's pro rata share of the total incremental gas costs incurred by the pipeline during that month.

The incremental pricing surcharge to be billed to each non-exempt industrial boiler fuel facility directly served by a natural gas supplier would be, in turn, the MSAC of the facility for the previous billing month or, if less than the MSAC, the facility's pro rata share of the total incremental gas costs incurred by the natural gas supplier during the previous calendar month.

Under the proposed regulations, incremental pricing surcharges would be stated as a flat dollar amount rather than on an Mcf basis. Any amounts remaining in the unrecovered incremental gas costs account which could not be passed through as a surcharge would be cleared to account 191 for recovery in the pipeline's next PGA period.

The proposal set forth below incorporates the suggestion made by the Natural Gas Pipeline Company of America to allow distributors to bill non-exempt industrial boiler fuel facilities at the level of the alternative fuel price ceiling applicable to the facility. If a local distribution company elects to so bill such a facility, the supplier would, in a later billing, adjust for any overrecovery.

The Commission believes that the potentially greatest obstacle to the successful operation of the UDC/Northern/Natural method of incremental pricing is the very short time permitted for reporting MSAC's up a chain of sale for resale customers. In order to allow for additional time to complete all reporting, the Commission proposes that the billing month for a non-exempt industrial boiler fuel facility end on or about the 20th day of each month. The Commission specifically

requests comments on this proposal and, especially, on whether the chain of reporting can be accomplished between the 20th day of a month and the date all information must be available in order to bill on the normal billing date the following month.

III. The Proposed Mechanism: An Alternative

The primary alternative to the "reduced PGA" approach would be to structure an incremental pricing mechanism along the lines suggested by the Interstate Natural Gas Association of America (INGAA) at the February and April conferences. The approach was described in detail in the appendix to the March 16, 1979, Notice convening the April conference. Briefly, under the INGAA approach, every month each interstate pipeline would: (1) bill all customers its normal PGA rate reflecting the full amount of its purchased gas costs, (2) bill non-exempt end users an incremental pricing surcharge, and (3) extend a pro rata credit to all exempt end users in the amount of the total incremental surcharges billed.

Incremental pricing surcharges would be computed each month on the basis of either: (1) the aggregate MSAC for the previous month (if the amount recorded in the incremental gas costs account at the beginning of the current month were greater than such aggregate MSAC) or (2) a pro-rata share of the amount recorded in the incremental gas costs account (if the amount charged to the incremental gas costs account at the beginning of the current month were less than the aggregate MSAC for the previous month).

The Commission, on the basis of the material presented to it, and its study and analysis, prefers the "reduced PGA" approach proposed by UDC, Northern and Natural. It is the Commission's view that such an approach has the advanage of being a less burdensome regulatory program for all affected parties.

The Commission notes, however, that it has given and will continue to give serious attention to the approach sponsored by INGAA. Those who believe that the Commission should adopt the INGAA approach in preference to the approach proposed here are invited to provide comments and arguments to that effect. Those who would advocate Commission adoption of still other alternatives are invited to present them in as much detail as possible.

IV. Exemptions

A. *Exemptions under §§ 206(a), (b) and (c) of the NGPA.*—Subsections 206(a), (b) and (c) of the NGPA provide that small existing industrial boiler fuel users, agricultural users, schools, hospitals and certain other facilities shall be exempt from incremental pricing. Section 282.204 of the proposed regulations would establish a procedure by which those exemptions could be obtained.

These regulations would be interim in nature for small boiler fuel facilities and agricultural users. Section 206 requires that by May 9, 1980, the Commission prescribe permanent exemption rules for these users. The permanent rules are to contain certain statutorily prescribed refinements of the interim rules.

Basically, under the proposed regulations, the exemptions permitted by subsections 206(a), (b) and (c) would be obtained by an industrial boiler fuel facility by filing an affidavit with the Commission and sending a copy to the facility's natural gas supplier. A copy of the proposed Exemption Affidavit is attached to the regulations below as Appendix A.

The Commission believes that affidavits for exemption should be updated on a regular basis so that if a facility no longer uses gas for exempt purposes, the facility would lose its exemption from incremental pricing. The Commission requests comments on how this updating should be done. The proposed regulations would require that annual reaffirmations of an affidavit for exemption be filed with the Commission. Another possible approach would be to make exemptions expire automatically when a change of

circumstances occurs with respect to the facility.

B. *Exemptions under section 206(d) of the NGPA.*—Under subsection 206(d) of the NGPA, the Commission may provide for the exemption of either individual industrial facilities or categories of such facilities which are not exempt from incremental pricing under subsections 206 (a), (b) and (c) of the Act. Any such action by the Commission is required to be submitted to the Congress for its review prior to the action taking effect. Either House of the Congress can veto a proposed exemption.

Section 282.206 of the proposed regulations would establish procedures whereby any interested person would be able to petition under subsection 206(d) of the NGPA for an exemption, in whole or in part, of any individual incrementally priced industrial facility or category of such facility.

During the informal conferences which were convened by staff in connection with the preparation of this Notice of Proposed Rulemaking, some participants suggested exemptions which the Commission could adopt under subsection 206(d). The suggestions generally fell into four categories:

An exemption for gas used in small boilers which have been constructed since November 9, 1978, and for gas used in boilers which were in existence on November 9, 1978, which used more than an average of 300 Mcf per day for boiler fuel during a calendar month of 1977, but which have used less than 300 Mcf per day since 1977;

A partial or complete exemption for gas used in industrial facilities which have the capabilities to use coal as an alternative fuel;

An exemption for gas used in industrial facilities which have the capability to use oil as an alternative fuel and which provide a load-balancing function on gas distribution systems; and

An exemption for gas used in industrial facilities in states where the prices of natural gas are at or above the FERC alternative fuel price ceilings on incremental pricing.

The Commission will, in several weeks, issue a Notice of Proposed Rulemaking in Docket No. RM79–48 regarding a new small boiler exemption. The Commission, at this time, does not intend to institute rulemakings with regard to the other three subsections 206(d) exemption proposals, however.

It is the Commission's view that an exemption for facilities which have the capability to burn coal rather than gas would have the effect of encouraging the consumption of gas rather than coal, and that such a result would be contrary to both national energy policy and the policies embodied in the National Energy Act of 1978.

It is also the Commission's view that an exemption for load-balancing customers which have the capability to burn oil is unnecessary. The Commission has proposed in Docket No. RM79–21 a method for determining alternative fuel price ceilings on incremental pricing that should minimize any load-shifting from gas to oil which otherwise might have occurred under incremental pricing. Thus, the benefits to a system of load-balancing customers who have the capability to burn oil will not be lost.

Finally, regarding the state-wide exemption proposal, the Commission believes it would be premature to attempt to determine at this stage whether any state can assure the Commission that it has a ratemaking program or procedure in effect which would accomplish the ends of incremental pricing as mandated by the NGPA. Any state program must be measured against the incremental pricing program established by this Commission, and particularly the alternative fuel price ceiling aspect of the program. Thus, only after final rules are adopted on, at least, the alternative fuel price ceiling will the Commission have established the point of comparison for state programs or plans which are described as satisfying the objectives of Title II of the NGPA.

As mentioned, comments regarding the coal exemption, the oil exemption and state-wide exemptions have, to this point, been made only in the highly informal context of the conferences convened prior to this Notice of

Proposed Rulemaking. In order to provide interested persons with a further opportunity to present to the Commission their views regarding these three exemption proposals, the Commission will provide an opportunity for further comments to be filed on the question of whether or not the Commission should establish a rulemaking proceeding with respect to any one of them.

Comments on establishing a rulemaking on the coal exemption should be filed in Docket No. RM79–45. Comments on establishing a rulemaking on the oil exemption should be filed in Docket No. RM79–46. Comments will be due by August 1, 1979.

Comments urging the Commission to establish one or more rulemaking proceedings on statewide exemption proposals should be filed in Docket No. RM79–47. The final date for filing comments in this docket will be September 1, 1979, in order to permit the parties to have before them the final rules to be issued in Docket No. RM79–21 and this docket.

Issues regarding subsection 206(d) exemptions, aside from questions regarding the procedures set forth in the proposed § 282.206, will not be further considered by the Commission in this proceeding, Docket No. RM79–14.

V. Time Line

The following is a brief time-line of the events which would take place under the incremental pricing regulations contained in this proposal and the companion docket to this proposal, Docket No. RM79–21. Comments are requested on all aspects of this time-line. (Minor conforming changes to the regulations proposed in RM79–21 will have to be made to comport with this time-line.)

August 1, 1979—Commission issues final regulations.

September 1, 1979—Regulations become effective. Exemption affidavits and alternative fuel price ceiling affidavits available through the Office of Public Information.

September 14, 1979—Natural gas suppliers mail exemption affidavits and alternative fuel price ceiling affidavits to all industrial boiler fuel facilities which were not determined to be exempt from an examination of the natural gas supplier's own records.

October 1, 1979—In accordance with the natural gas suppliers' requests as contained in the suppliers' mailings of September 14, exemption affidavits are returned to natural gas suppliers by industrial boiler fuel facilities claiming an exemption in whole or in part.

October 15, 1979—Local distribution companies notify supplying pipelines of their projected MSAC's for the period commencing January 1, 1980.

November 1, 1979—Interstate pipelines file revised PGA provisions and incremental pricing surcharge provisions; pipelines determine projected MSAC's.

December 1, 1979—Interstate pipelines file reduced PGA tariff sheets and estimated incremental pricing surcharge tariff sheets for the period commencing January 1, 1980.

January 1, 1980—Effective date of tariff sheet filed December 1, 1979. Incremental gas acquisition costs begin to be booked by natural gas suppliers.

January 15, 1980—Natural gas suppliers file lists of non-exempt industrial boiler fuel facilities with the Federal Energy Regulatory Commission.

December 15, 1980—Natural gas suppliers mail exemption reaffirmation affidavits and alternative fuel price ceiling reaffirmation affidavits to exempt industrial boiler fuel facilities and non-exempt boiler fuel facilities.

December 31, 1980—Industrial boiler fuel facilities return exemption reaffirmation affidavits and alternative fuel price ceiling reaffirmation affidavits to the Commission and the natural gas supplier.

January 15, 1981—Updated lists of non-exempt industrial boiler fuel facilities are filed with the Commission.

VI. Direct Sales

The regulations set forth below propose the use of unregulated contract rates for the calculations of MSAC's of interstate pipelines' direct sale customers. The reason for this approach is that the Commission did not have jurisdiction over such sales under the

Natural Gas Act,[1] and the Commission has found minimal support in the provisions of the NGPA to permit it to take jurisdiction with respect to such sales.

It can be argued, however, that the Congressional intent underlying Title II was not only to protect high priority consumers from increased gas acquisition costs, but to maximize that protection by, among other things, maximizing the surcharges to direct non-exempt customers. This Congressional intent could arguably establish a new basis for jurisdiction.

The regulations below, thus, reflect use of the contract rate merely for purposes of generating comments and further discussion. The proposal does not reflect a conclusion that the contract rate approach is the only one available to the Commission. There are several conceivable alternative approaches. In each approach, the higher determinant of the MSAC would be the established applicable alternative fuel price ceiling. The number which would be used for the lower determinant could be:

(1) The unit cost allocated to non-jurisdictional service in the pipeline's last rate proceeding;

(2) The sum of (i) the unit cost allocated to non-jurisdictional service in the pipeline's last rate proceeding and (ii) 50 percent of the difference between the allocated unit cost and the alternative fuel price ceiling;

(3) The sum of (i) the unit cost allocated to non-jurisdictional service in the pipeline's last rate proceeding and (ii) the difference existing on June 1, 1979, between the contract rate and that allocated unit cost;

(4) The contract rate, as determined under the terms of the existing contract as that contract was in efect on June 1, 1979; or

(5) The product of (i) the unit cost allocated to non-jurisdictional service in the pipeline's last rate proceeding and (ii) the ratio of the contract rate as of June 1, 1979, to the unit cost allocated to non-jurisdictional service in the pipeline's last rate proceeding prior to June 1, 1979.

Each of these possible approaches raises jurisdictional issues. As for the first approach, the outermost limit on interstate pipeline rates to direct sale customers is the cost of alternative fuels. Thus, defining direct sale MSAC's as the difference between the level of allocated costs and the level of the alternate fuel price would effectively dictate to a pipeline its markup in a direct sale.

Methods two through five above would at least allow the pipeline a range in which it could negotiate a retail price. In no case would the pipeline's potential markup over allocated costs be reduced to zero or would the retail rate be specifically determined.

Public comment is invited regarding the merits of all of the proposed methods for determining direct sale MSAC's. It is requested that comments address the jurisdictional implications of the proposed methods. As indicated above, the method of determining direct sale MSAC's on the basis of contract rates will be reviewed in light of the comments received, and may be revised as appropriate in light of those comments.

VII. Submetering

The January 12, 1979, staff proposal in this docket provided, in effect, that all natural gas used at a nonexempt industrial boiler fuel facility would be subject to incremental pricing unless the non-exempt boiler fuel usage was separately metered.

A number of commenters opposed the staff proposal. Several commenters contended that installing submeters would entail large capital expenditures to perform a task—quantifying volumes consumed for exempt or process uses in a non-exempt facility—which can be done by means not requiring new capital investment. Further, it was

[1] *Panhandle Eastern Pipe Line Company* v. *Public Service Commission of Indiana*, 332 U.S. 507 (1947); *City of Hastings* v. *F.P.C.* 221 F. 2d 31 (D.C. Cir. 1954), *cert. denied*, 349 U.S. 920 (1955).

argued that such an expenditure may be rendered moot in whole or in part by the 18-month rule required by Section 202 of Title II. Lastly, it was claimed that the requisite number of meters could not be obtained and installed by the anticipated January 1, 1980, implementation date for incremental pricing.

A submetering requirement would also raise secondary questions as to who should bear the cost—the end user, the distributor, or the pipeline—inasmuch as the incremental pricing program is intended to benefit exempt users.

Several commenters acknowledged that submetering may be necessary, or would at least be preferable to the alternatives which were suggested. The most viable of these alternatives would be to utilize certified estimates in place of actual volume usage as recorded by meters.

The Commission has determined, based on all of the information available to it, that the original staff proposal on submetering, modified to a certain extent, should be retained in this proposal. The slight modification would permit either exempt (including process) or non-exempt uses to be metered, so long as a total volume of non-exempt usage is derivable from meter readings.

Based on the trade press,[2] and staff's study and observations, we believe that considerable in-plant submetering already is being done. In an era of ever-rising energy costs, many companies have determined that they want to know where and in what quantities energy (in any form) is being used.

Further, it appears that submeters can be purchased and installed at reasonable cost. For many industrial applications, a meter installation for loads up to 1000 Mcf per day, for example, would total less than $5000.[3] If such a meter enabled a non-exempt user to reduce its gas bill by as little as 10 cents per Mcf by having 1000 Mcf per day exempted from incremental pricing by submetering, the cost of the meter would be recovered in 50 days or less.

On the question of the availability of submeters, we request additional comment and statistical data on how widespread the use of submetering aleady is, on the numbers of meters that would be needed, and the time required to obtain and install such meters.

For purposes of incremental pricing, it is immaterial whether the exempt or non-exempt volumes are directly measured. If one is measured, the other can be determined. Thus, comments on the number (and cost) of meters should consider the question in terms of accomplishing the metering task in the most efficient manner.

As to the ownership of the submeters, the Commission currently believes that the end user should bear the cost. The end-user is the potential beneficiary of submetering since it would thereby acquire an exemption for non-boiler fuel uses. End-user ownership of meters would avoid the problem of a utility having its property on the end-user's site and would avoid the myriad of regulatory problems inherent in utility ownership. End-user ownership should also tend to maximize the tax benefits generated by the purchase and installation of submeters.

As mentioned above, the most viable alternative to submetering for purposes of identifying volumes which should not be subject to an incremental pricing surcharge would be to use estimates of gas consumption. Some commenters suggested, however, that if used, estimates should be subjected to review by Data Verification Committees (DVC's). Proponents of DVC's cited their useful role in minimizing litigation and resolving disputes in pipeline curtailment cases. DVC opponents raised the spectre of the on-going cost

[2] *E.g., Modern Industrial Energy*, April 1979, p. 12, 13; *Energy User News*, Aug. 14, 1978, p. 1, 10, 11; *Plant Energy Management*, Sept/Oct 1978, p. 40, 42; *Gas Industries*, Sept. 1978, p. 22, Oct. 1977, p. 22, 23.

[3] For example, according to its May 1978 price list, an American Meter Company Model 11M, aluminum housing CVM positive displacement meter capable of measuring over 1100 Mcf per day at 50 psig line pressure would cost less than $2000, F.O.B. Erie, PA. Installation and shipping costs should not result in a drastically increased total cost.

and administrative burden of establishing and maintaining DVC's, in addition to the question of whether they could complete their tasks prior to the expected January 1, 1980, implementation date for the incremental pricing program.

The Commission does not currently view the use of estimates and DVC's as a viable long-term alternative to submetering. The ongoing commitment of professional talent for an indefinite period of time to accomplish the same task that can be—and in many cases already is being—done by meters, would appear to be an overly burdensome regulatory solution.

To the extent, however, that meters cannot be acquired and installed by January 1, 1980, some short-term use of estimates may be needed. One possible approach would be to permit estimates for the period January–March of 1980, based on actual meter readings for 30 days of continuous use at some point during calendar year 1979. Under this approach, a facility could utilize one meter to measure the usage of several boilers until such time as meters could be installed as needed on a permanent basis. Commenters are requested to describe, in as much detail as possible, whether and how a short-term estimating procedure should be implemented.

VIII. Environmental Issues

The staff has completed its environmental assessment of this proposed rulemaking. Staff has concluded, based on the information currently available, that the proposed regulations would not be a major Federal action significantly affecting the quality of the human environment.

This environmental assessment has been made part of the public record in this docket and in Docket No. RM79–21. It is available for inspection in the Commission's Office of Public Information.

The Commission requests comments on any environmental issues which are believed relevant to this rulemaking and on what is believed to be the scope of the Commission's responsibility in this area. Comments relating to environmental issues should, if possible, be substantiated with detailed analysis.

IX. Comments Requested

The Commission requested comments on all aspects of the proposed regulations set forth below. The Commission particularly invites comments on the issues identified above and on approaches to those issues other than the ones reflected in the regulations below.

X. Comment Procedures

A. *Written Comments*

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79–14. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, July 9, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

B. *Public Hearing*

A public hearing concerning this proposal will be held in Washington, D.C. on June 27, 1979. The hearing will be held at the Federal Energy Regulatory Commission, Hearing Room "A", 825 North Capitol Street, N.E., Washington, D.C. 20426, and will begin at 10:00 a.m. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at this hearing provided that a written request to

participate is submitted to the Secretary of the Commission at the address given above by June 22, 1979. Requests to participate should include a reference to Docket No. RM79–14, should indicate the amount of time desired, and should include a telephone number where the person making the request may be reached. A list of the participants in the hearing will be available in the Commission's Office of Public Information on June 25, 1979 and will be available at the site of the hearing on the morning of the hearing. The presiding officer is authorized to limit oral presentations at the hearing both as to length and as to substance. Participants should, if possible, bring 150 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons making statements. The presiding officer will question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available in the public file for this proceeding, Docket No. RM79–14, in the Commission's Office of Public Information.

The Commission proposes to make these amendments, when adopted, effective on September 1, 1979. As noted above, Title II of the NGPA requires that final regulations be in place by November 9, 1979. In order that both the regulations set forth below and the regulations to be adopted in Docket No. RM79–21 can be implemented with the least disruption to currently followed reporting and accounting practices, the Commission proposes to adopt these regulations prior to the November 9th deadline.

(Natural Gas Act as amended, 15 U.S.C. 17 *et seq.*; the Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*; the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, it is proposed to amend Title 18 of the Code of Federal Regulations in Parts 154, 201, 204 and by the addition of a new Part 282, to read, in part, as set forth below.

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 154—RATE SCHEDULES AND TARIFFS

1. Section 154.38 is amended in paragraph (d) by revising subparagraph (1) and clause (iv) (*a*) of subparagraph (4) to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(d) *Statement of rate.* (1) Except as permitted in §§ 154.52, 154.82, and Part 282, all rates shall be clearly stated in cents or in dollars and cents per unit. Only the rates and charges to be used in current billing shall be included in the rate schedules. * * *

(4) * * *

(iv)(*a*) Rate changes which reflects both the projected [3] cost of purchased gas and a revised surcharge to clear the amounts accrued in the deferred account for both producer and pipeline suppliers shall be computed and filed not more frequently than semi-annually.

* * * * *

PART 201—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT (CLASS A AND CLASS B)

2. Part 201, account 191 is amended in paragraph A to read as follows:

191 Unrecovered purchased gas costs.

A. This account shall include purchased gas costs related to

[3] Pipeline companies may reflect in their rates during their normal PGA period monthly changes in the ceiling rates permitted producers of natural gas under the Natural Gas Policy Act of 1978.

Commission approved purchased gas adjustment clauses when such costs are not included in the utility's rate schedules on file with the Commission. This account shall also include such other costs as authorized by the Commission. Costs of purchased gas subject to passthrough under the incremental pricing requirements of the Commission shall be excluded from this account and included in account 192.1, Unrecovered Incremental Gas Costs.

* * * * *

3. Part 201 is amended to add a new account 192.1 to read as follows:

192.1 Unrecovered incremental gas costs.

A. This account shall include the unrecovered costs of purchased gas which are subject to passthrough by means of an incremental pricing surcharge. This account shall also include any other costs authorized by the Commission.

B. This account shall be debited and account 805.2, Incremental Gas Cost Adjustments, shall be credited for unrecovered costs of purchased gas subject to incremental pricing.

C. This account shall be credited and account 805.2 debited for those costs included in this account which are passed through by means of incremental pricing surcharges.

D. Those costs accumulated in this account for gas received during a calendar month which are not subject to passthrough by incremental pricing surcharges because of alternative fuel price ceilings shall be transferred to account 191, Unrecovered Purchased Gas Costs, no later than the end of the month in which the applicable surcharges are billed.

E. Separate subaccounts shall be maintained for the accumulation of incremental gas costs each calendar month and the passthrough or transfer of such costs so as to keep each period separate.

4. Part 201 is amended to add a new account 192.2 to read as follows:

192.2 Unrecovered incremental surcharges.

A. This account shall include any incremental pricing surcharges passed through to the company by pipeline suppliers.

B. This account shall be debited and account 805.2, Incremental Gas Cost Adjustments, shall be credited with the amount of each incremental pricing surcharge as incurred.

C. This account shall be credited and account 805.2 shall be debited with the amounts included in this account which are passed through to customers.

5. Part 201 is amended to add a new account 805.2 to read as follows:

§ 805.2 Incremental gas cost adjustments.

A. This account shall be credited with the costs of purchased gas which are subject to passthrough by means of incremental pricing surcharges.

B. This account shall also be credited with any incremental pricing surcharges passed through to the company by pipeline suppliers.

C. This account shall be debited with amounts from account 192.1, Unrecovered Incremental Surcharges, which are passed through by means of incremental pricing surcharges.

D. This account shall also be debited with amounts from account 192.2, Unrecovered Incremental Surcharges, which are passed through by means of incremental pricing surcharges.

PART 204—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT (CLASS C AND CLASS D)

6. Part 204, account 191 is amended in paragraph A to read as follows:

191 Unrecovered purchased gas costs.

A. This account shall include purchased gas costs related to Commission approved purchased adjustment clauses when such costs are not included in the utility's rate

schedules on file with the Commission. This account shall also include such other costs as authorized by the Commission. Costs of purchased gas subject to passthrough under the incremental pricing requirements of the Commission shall be excluded from this account and included in account 192.1, Unrecovered Incremental Gas Costs.

* * * * *

7. Part 204 is amended to add a new account 192.1 to read as follows:

192.1 Unrecovered incremental gas costs.

A. This account shall include the unrecovered costs of purchased gas which are subject to passthrough by means of incremental pricing surcharges. This account shall also include any other costs authorized by the Commission.

B. This account shall be debited and account 731.2, Incremental Gas Cost Adjustments, shall be credited for unrecovered costs of purchased gas subject to incremental pricing.

C. This account shall be credited and account 731.2 debited for those costs included in this account which are passed through by means of incremental pricing surcharges.

D. Those costs accumulated in this account for gas received during a calendar month which are not subject to passthrough by incremental pricing surcharges because of alternative fuel price ceilings shall be transferred to account 191, Unrecovered Purchased Gas Costs, no later than the end of the month in which the applicable surcharges are billed.

E. Separate subaccounts shall be maintained for the accumulation of incremental gas costs each calendar month and the passthrough or transfer of such costs so as to keep each period separate.

8. Part 204 is amended to add a new account 192.2 to read as follows:

192.2 Unrecovered incremental surcharges.

A. This account shall include incremental pricing surcharges passed through to the company by its pipeline suppliers.

B. This account shall be debited and account 731.2, Incremental Gas Cost Adjustments, shall be credited with the amount of each incremental pricing surcharge as incurred.

C. This account shall be credited and account 731.2 shall be debited with the amounts included in this account which are passed through to customers.

9. Part 204 is amended to add a new account 731.2 to read as follows:

§ 731.2 Incremental gas cost adjustments.

A. This account shall be credited with the costs of purchases gas which are subject to passthrough by means of incremental pricing surcharges.

B. This account shall also be credited with any incremental pricing surcharges passed through to the company by its pipeline suppliers.

C. This account shall be debited with amounts from account 192.1, Unrecovered Incremental Gas Costs, which are passed through by means of incremental pricing surcharges.

D. This account shall also be debited with amounts from account 192.2, Unrecovered Incremental Surcharges, which are passed through by means of incremental pricing surcharges.

10. Subchapter I of Chapter 1 is amended by adding a new Part 282 to read as follows:

PART 282—INCREMENTAL PRICING

Subpart A—General Rules and Definitions

Sec.

282.101 Purpose.
282.102 Applicability and effective date.
282.103 Definitions.

Subpart B—Exemptions

282.201 General rule.
282.202 Definitions.
282.203 Exempt end-uses.
282.204 Obtaining an exemption.
282.205 Annual reinstatement of exemptions.
282.206 Petitions for exemptions under § 206(d).

Subpart C—Determination of Costs Subject to Incremental Pricing

282.301 Costs subject to incremental pricing.
282.302 Gas qualifying under more than one provision.
282.303 First sale acquisition cost.
282.304 Incremental pricing threshold.

Subpart D [Proposed in notice of proposed rulemaking issued May 11, 1979 (44 FR 29090, May 18, 1979)]

Subpart E—Incremental Pricing Accounts and Surcharges

282.501 General rule.
282.502 Accounting.
282.503 PGA reduction.
282.504 Incremental pricing surcharge.
282.505 Recovery of amounts in excess of maximum surcharge absorption capabilities.

Subpart F—Filing Requirements

282.601 FERC gas tariff provisions.
282.602 Tariff sheets.
282.603 Informational filings.

Authority: This part is issued under the Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.;* the Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.;* the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.;* E.O. 12009, 42 FR 46267.

Subpart A—General Rules and Definitions [1]

§ 282.101 Purpose.

The purpose of this part is to set forth an incremental pricing rule in accordance with Title II of the Natural Gas Policy Act of 1978. The rule requires that certain costs of acquiring natural gas be passed through as a surcharge on sales of natural gas used as specified in the rule.

§ 282.102 Applicability and effective date.

(a) *Uses.* Natural gas used as boiler fuel in industrial boiler fuel facilities on and after January 1, 1980, shall be subject to incremental pricing under this part.

(b) *Costs.* Costs described in Subpart C and incurred by natural gas suppliers on or after January 1, 1980 shall be subject to this part.

(c) *Natural gas suppliers.* Interstate pipelines and local distribution companies shall be subject to this part.

(d) *Effective date.* The provisions of this part shall be effective September 1, 1979.

§ 282.103 Definitions.

For purposes of this part:

(a) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(b) "Industrial facility" means any facility which primarily changes raw or unfinished materials into another form or product.

(c) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the provisions of this part in accordance with Subpart B.

(d) "No. 2 fuel oil" means No. 2 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(e) "No. 6 fuel oil" means No. 6 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(f) "Low sulfur fuel oil" means any oil containing 1 percent (1%) or less sulfur content by weight.

(g) "High sulfur fuel oil" means any oil containing more than 1 percent (1%) sulfur content by weight.

(h) "British thermal unit" or "Btu" shall have the meaning set forth in § 270.102.

Subpart B—Exemptions

282.201 General rule.

(a) *Statutory exemptions.* Natural Gas used for purposes described in § 282.203 shall be exempt from incremental pricing as provided in subsections

[1] For convenience of the reader, most of Subpart A as it appears here was included in the Notice of Proposed Rulemaking issued in Docket No. RM79-21 on May 11, 1979 (44 FR 29090, May 18, 1979). Commenters are asked to comment on Subpart A in this docket rather than in Docket No. RM79-21.

206(a), (b) and (c) of the NGPA. Exemptions for such gas may be obtained in the manner prescribed in § 282.204. Adjustments under authority of subsection 502(c) of the NGPA as may be necessary to prevent special harship, inequity, or unfair distribution of burdens may be obtained as provided in § 1.41.

(b) *Discretionary exemptions.* Petitions for an exemption under authority of subsection 206(d) of the NGPA may be filed in the manner prescribed in § 282.206.

§ 282.202 Definitions.

For the purposes of this subpart:

(1) "Qualifying cogeneration facility" means a cogeneration facility which meets the requirements prescribed in § ——.

(2) "School" means a facility the primary function of which is the delivery of instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the delivery of instruction.

(3) "Hospital" means a facility the primary function of which is the delivery of medical care to patients who remain at the facility. Outpatient clinics or doctor's offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(4) "Similar institution" means a facility the primary function of which is the same as the primary function of the facility to which it is compared.

(5) "Agricultural use" means any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR § 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA.

§ 282.203 Exempt end-uses.

Natural gas used for the following purposes shall be exempt from incremental pricing under this part:

(a) All gas used for boiler fuel by an industrial boiler fuel facility which was:

(1) In existence on November 9, 1978; and

(2) Did not consume more than an average of 300 Mcf per day for boiler fuel during any calendar month of calendar year 1977;

(b) All gas used for an agricultural use;

(c) All gas used in a qualifying cogeneration facility;

(d) All gas used for the generation of electricity by an electric utility; and

(e) All gas used in a school, hospital, or similar institution.

§ 282.204 Obtaining an exemption.

(a) *General.* This section establishes procedures by which owners or operators of industril boiler fuel facilities may obtain an exemption for natural gas used for the purposes described in § 282.203.

(b) *Determination of industrial boiler fuel facilities.* On or before September 14, 1979, each natural gas supplier shall determine which facilities served directly by it are industrial boiler fuel facilities.

(c) *Exemption on the basis of company records.* (1) On or before September 14, 1979, each natural gas supplier shall determine from an examination of its records which industrial boiler fuel facilities, as identified under paragraph (b), were in existence on November 9, 1978, and either:

(i) Did not use more than an average of 300 Mcf per day during any calendar month of calendar year 1977; or

(ii) Did not use more than an average of 300 Mcf per day for boiler fuel during any calendar month of calendar year 1977.

(2) Natural gas used by an industrial boiler fuel facility for which an affirmative determination is made under subparagraph (1) shall be exempt from incremental pricing under this part.

(d) *Exemption on the basis of affidavit.* (1) *Commission to provide exemption affidavits.* As of the effective date of this part, exemption affidavits as described in subparagraph (3) will be

available to natural gas suppliers for purposes of subparagraph (2) and to any other interested person upon request from the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

(2) *Availability of exemption affidavits from natural gas suppliers.* (i) *Initial service.* Not later than September 14, 1979, each natural gas supplier shall mail or otherwise supply an exemption affidavit, as described in subparagraph (3), to the owner or operator of each industrial boiler fuel facility on such natural gas supplier's system which the natural gas supplier did not determine to be exempt pursuant to paragraph (c).

(ii) *Response date.* Natural gas suppliers which supply exemption affidavits under clause (i) shall request that executed affidavits be filed on or before October 1, 1979, in accordance with subparagraph (4).

(iii) *Ongoing availability.* After September 14, 1979, natural gas suppliers shall make exemption affidavits available at their principal place of business on an ongoing basis during regular business hours.

(3) *Contents of exemption affidavit.* (i) The exemption affidavit will provide the owner or operator of an industrial boiler fuel facility with an opportunity to respond to the following questions:

(A) Did the customer's facility, on the basis of records, documents, or data in the customer's possession, consume no more than an average of 300 Mcf per day for boiler fuel during any calendar month of calendar year 1977?

(B) Is all of the natural gas consumed at the customer's facility used as boiler fuel for an agricultural use?

(C) Is the customer's facility, in its entirety, a qualifying cogeneration facility?

(D) Is the customer's facility, in its entirety, a school, hospital, or similar facility?

(E) Is the customer's facility, in its entirety, used for the generation of electricity by an electric utility?

(F) Is a portion, though not all, of the gas consumed at the customer's facility used as boiler fuel for an agricultural use?

(G) Is the customer's facility, in part but not in its entirety, a qualifying cogeneration facility?

(H) Is the customer's facility, in part but not in its entirety, a school, hospital, or similar facility?

(I) Is the customer's facility, in part but not in its entirety, used for the generation of electricity by an electric utility?

(ii) The exemption affidavit will notify the customer that, if he affirmatively responds to any of the questions (F) through (I), volumes of natural gas used in the customer's facility will be exempt from incremental pricing only to the extent that the customer maintains submeters and records as required by subparagraph (6).

(iii) The exemption affidavit will indicate the record retention obligation which may be incurred by the customer under subparagraph (8) of this paragraph.

(iv) The exemption affidavit will contain such other information as may be necessary for completion and return of the affidavit.

(4) *Filing of exemption affidavits.* In order to obtain an exemption from incremental pricing, an owner or operator of an industrial boiler fuel facility shall file an executed exemption affidavit, signed and dated by a responsible official, under oath, with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and send a copy of the executed affidavit to the natural gas supplier serving the industrial boiler fuel facility.

(5) *Effect of filing an exemption affidavit.* (i) If the owner or operator of an industrial boiler fuel facility affirmatively responds to any of the questions (A) through (E), as set out in subparagraph (3), and files the affidavit in accordance with subparagraph (4), then natural gas used in the facility shall

be exempt from incremental pricing under this part.

(ii) If the owner or operator of an industrial boiler fuel facility affirmatively responds to any of the questions (F) through (I) as set out in subparagraph (3), and files the affidavit in accordance with subparagraph (4), then natural gas used in the industrial boiler fuel facility shall be exempt from incremental pricing to the extent determined in accordance with the applicable provision of subparagraph (6).

(6) *Determination of extent of partial exemption.* (i) If the owner or operator of an industrial boiler fuel facility affirmatively responds to question (F) as set out in subparagraph (3), the volume of natural gas used in the facility which shall be exempt from incremental pricing shall be determined on the basis of and to the extent there are submeter reading records for each billing month, as signed under oath by a responsible company official, that show the extent to which gas is consumed for an agricultural use and that are made available to the facility's natural gas supplier as required by the supplier for billing purposes.

(ii) If the owner or operator of an industrial boiler fuel facility affirmatively responds to any of the questions (G) through (I), the volume of natural gas used in the facility which shall be exempt from incremental pricing shall be determined on the basis of and to the extent there are submeters which permit determination of the volume of exempt usage and which are available to be read by the facility's natural gas supplier as required for billing purposes.

(7) *Effective date of exemption.* (i) If the owner or operator of an industrial boiler fuel facility files an exemption affidavit with the Commission and sends a copy to the facility's natural gas supplier in accordance with subparagraph (4) on or before December 31, 1979, the facility shall be exempt from incremental pricing under this part as of January 1, 1980.

(ii) If the owner or operator of an industrial boiler fuel facility files an exemption affidavit with the Commission and sends a copy to the facility's natural gas supplier in accordance with subparagraph (4) on or after January 1, 1980, the facility shall be exempt from incremental pricing under this part as of the beginning of the first full billing month following the date the exemption affidavit is filed with the Commission and received by the facility's natural gas supplier.

(8) *Record retention.* If the owner or operator of an industrial boiler fuel facility obtains an exemption as a result of affirmatively responding to question (A) as set out in subparagraph (3), the owner or operator shall retain all records, documents or data which formed the basis of the response.

(e) *Public availability of exemption information.* (1) *Executed exemption affidavits.* (i) Copies of executed exemption affidavits which are filed with the Commission shall be available for public inspection at the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426.

(ii) Each natural gas supplier shall maintain copies of all executed exemption affidavits which it has received and shall make such copies available for public inspection at its principal place of business during regular business hours.

(2) *Lists of non-exempt facilities.* (i) On or before January 15, 1980, each natural gas supplier shall file with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, a list of all industrial boiler fuel facilities on each supplier's system which did not qualify for an exemption under paragraph (c) or (d) as of December 31, 1979.

(ii) On or before January 15th of each year after 1980, each natural gas supplier shall file a revised list of the non-exempt industrial boiler fuel facilities on such supplier's system. A revised list shall indicate all additions to or deletions from the prior year's list

and shall reflect determinations and reaffirmations made pursuant to § 282.205.

(iii) Lists of non-exempt facilities filed in accordance with clause (i) or (ii) shall be available for public inspection through the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426.

(iv) Each natural gas supplier shall make lists filed in accordance with clause (i) or (II) available for public inspection at its regular place of business during regular business hours.

(f) *Protests.* Any interested person may protest the exemption of an industrial boiler fuel facility form incremental pricing. The procedures set forth in § 1.10 shall govern the filing of such a protest.

§ 282.205 Annual reinstatement of exemptions.

(a) *Review of exemption determinations by natural gas suppliers.* On or before December 31, 1980, and December 31st of every year thereafter, each natural gas supplier shall review the determinations made by its pursuant to § 282.204(b) in order to ascertain whether all such determinations remain accurate.

(b) *Filing of reaffirmations of eligibility for exemption.* On or before December 31st of 1980 and of every year thereafter, the owner or operator of each industrial boiler fuel facility which has been exempted in part or in whole from the incremental pricing program during the immediately preceding calendar year through the filing of an exemption affidavit pursuant to § 282.204(d) or a reaffirmation of such affidavit, as set forth herein, shall, if appropriate, file a reaffirmation of eligibility for exemption from the incremental pricing program, signed and dated by a responsible official, under oath, with the Secretary, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, and send a copy of the executed reaffirmation affidavit to the natural gas supplier serving the industrial boiler fuel facility.

(c) *Effect of not filing a reaffirmation.* (1) If a natural gas supplier does not receive by December 31st of 1980 and every year thereafter a reaffirmation of eligibility with respect to an industrial boiler fuel facility which it has treated as a partially or wholly exempt facility during the immediately preceding calendar year, the natural gas supplier shall add the facility to the list of non-exempt industrial boiler fuel facilities which it files with the Commission under § 282.204(e)(2)(ii) and shall treat the facility as a non-exempt facility beginning with the next full billing month following the December 31 date.

(2) An industrial boiler fuel facility may file an entirely new exemption affidavit rather than a reaffirmation affidavit in order to reflect a change of circumstances in the operations of the facility.

(d) *Commission to provide reaffirmation affidavits.* Affidavits for the reaffirmation of eligibility for exemption from the incremental pricing program will be available to natural gas suppliers and to any other interested person upon request from the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426.

(e) *Natural gas suppliers to make reaffirmation affidavits available.* (1) *Initial service.* On or before December 15, 1980 and December 15 of each following year, each natural gas supplier shall mail or otherwise supply a reaffirmation affidavit to the owner or operator of each industrial boiler fuel facility which has been exempted in whole or in part from the incremental pricing program during the immediately preceding calendar year through the filing of either an exemption affidavit pursuant to § 282.204(d) or a reaffirmation of eligibility affidavit pursuant to paragraph (b).

(2) *Ongoing availability.* Natural gas suppliers shall make reaffirmation affidavits available at their principal place of business on an ongoing basis during regular business hours.

§ 282.206 Petitions for exemptions under § 206(d).

(a) *General rule.* Any interested person may petition under authority of subsection 206(d) of the NGPA for the exemption, in whole or in part, of any non-exempt industrial boiler fuel facility or category thereof.

(b) *Filing requirements.* A petition for an exemption under authority of subsection 206(d) shall:

(1) Conform to the requirements of § 1.7;

(2) Contain sufficient information and data to permit review of the petition on the merits; and

(3) Provide an analysis of any environmental issues which are relevant to the request for an exemption.

(c) *Notice.* Public notice of the filing of a petition for an exemption under authority of subsection 206(d) shall be given with opportunity for comment by interested persons.

(d) *Denial without prejudice.* A petition for an exemption under authority of subsection 206(d) which is not acted upon within 60 days of the date for submission of comments shall be deemed denied without prejudice.

Subpart C—Determination of Costs Subject to Incremental Pricing

§ 282.301 Costs subject to incremental pricing.

The costs specified in this section are acquisition costs which shall be subject to the passthrough provisions of this part.

(a) *New natural gas.* In the case of new natural gas (as defined in section 102(c) of the NGPA), any portion of the first sale acquisition cost of such natural gas which exceeds the incremental pricing threshold applicable for the month in which the delivery of such natural gas occurs shall be subject to this part.

(b) *Natural gas under intrastate rollover contract.* In the case of natural gas delivered under a rollover contract which was not committed or dedicated to interstate commerce on November 8, 1978, any portion of the first sale acquisition cost of such natural gas which exceeds the incremental pricing threshold applicable for the month in which the delivery occurs shall be subject to this part.

(c) *New, onshore production well gas.* In the case of natural gas produced from any new, onshore production well (as defined in section 103(c) of the NGPA), any portion of the first sale acquisition cost of such natural gas which exceeds the incremental pricing threshold applicable for the month in which the delivery of such natural gas occurs shall be subject to this part.

(d) *LNG imports.* (1) Subject to the provisions in subparagraph (2), in the case of liquefied natural gas imported into the United States, any portion of the first sale acquisition cost of such natural gas (whether or not liquefied when acquired) which exceeds the incremental pricing threshold applicable for the month in which such liquefied natural gas enters the United States shall be subject to this part.

(2) Costs of liquefied natural gas imported into the United States shall not be subject to this part if:

(i) The importation of the liquefied natural gas was authorized under section 3 of the Natural Gas Act on or before May 1, 1978;

(ii) An application for such authority was pending under section 3 of the Natural Gas Act on such date, except as set forth in subparagraph (3) below; or

(iii) In connection with the granting of any authority under the Natural Gas Act to import such liquefied natural gas, the Secretary of the Department of Energy or the Commission, in accordance with the Department of Energy Organization Act (or any delegation or assignment thereunder), determines that a contract binding on the importer or other substantial financial commitment of the importer was made on or before such date, except as set forth in subparagraph (3) below.

(3) Clauses (ii) and (iii) of subparagraph (2) shall not apply with respect to any liquefied natural gas imports if, in connection with the

granting of any authority under the Natural Gas Act to import such liquefied natural gas, the Secretary of the Department of Energy or the Commission, in accordance with the assignment of functions under the Department of Energy Organization Act, determines that the portion of the costs of such imports as described in subparagraph (1) shall be subject to this part.

(e) *Natural gas (other than LNG) imports.* (1) Subject to subparagraph (2), in the case of natural gas (other than liquefied natural gas) imported into the United States, any portion of the first sale acquisition cost of such imported natural gas which exceeds the maximum lawful price, per million Btu's, computed under section 102 of the NGPA (relating to new natural gas) for the month in which such natural gas enters the United States without regard to section 110 of the NGPA, shall be subject to this part.

(2) Subject to subparagraph (3), subparagraph (1) shall only apply to costs of volumes of natural gas (other than liquefied gas) imported into the United States which exceed both:

(i) The maximum delivery obligations for the month in which such delivery of natural gas occurs, as specified by contracts entered into on or before May 1, 1978 and in effect when such delivery occurs; and

(ii) The volume of natural gas imported into the United States by the interstate pipeline involved during the corresponding month of calendar year 1977.

(3) Subparagraph (2) notwithstanding, subparagraph (1) shall apply to the portion of first sale acquisition costs, as described in subparagraph (1), of volumes of natural gas (other than liquefied natural gas) imported into the United States which exceed the volume of natural gas imported into the United States by the interstate pipeline involved during calendar year 1977 if, in connection with the granting of any authority under the Natural Gas Act to import such natural gas, the Secretary of the Department of Energy or the Commission, in accordance with the assignment of functions under the Department of Energy Organization Act, determines that subparagraph (1) shall apply with respect to such natural gas imports.

(f) *Stripper well natural gas.* In the case of stripper well natural gas (as defined in section 108(b) of the NGPA) any portion of the first sale acquisition cost of such natural gas which exceeds the maximum lawful price, per million Btu's, computed under section 102 of the NGPA (relating to new natural gas) for the month in which the delivery of such gas occurs without regard to section 110 of the NGPA, shall be subject to this part.

(g) *High-cost natural gas.* In the case of high-cost natural gas (as defined in section 107(c) of the NGPA), any portion of the first sale acquisition cost of such natural gas which exceeds 130 percent of—

(1) The weighted average per barrel cost of No. 2 fuel oil landed in the greater New York City metropolitan area, as published by the energy Information Administration of the Department of Energy, during the month preceding the month in which delivery of such natural gas occurs, divided by,

(2) A Btu conversion factor of 5.8 million Btu's per barrel—shall be subject to this part.

(h) *Alaska Natural Gas Transportation System.* In the case of natural gas produced from the Prudhoe Bay Unit of Alaska (as defined in section 2 of the NGPA), and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976, the following amounts shall be subject to this part:

(1) Any portion of the first sale acquisition cost of natural gas which is not described in subparagraph (2) and which exceeds the maximum lawful price, per million Btu's computed under section 109 of the NGPA (relating to other categories of natural gas) for the month in which delivery of such natural gas occurs without regard to section 110 of the NGPA; and

(2) Any amount paid to any person (other than the producer of such natural gas or an affiliate of such producer) for, or attributable to, any compressing, gathering, processing, treating, liquefying, or transporting of such natural gas, or any similar service provided with respect to such natural gas, before the delivery of such natural gas to such system.

(i) *Increased state severance taxes.* (1) Subject to the provisions of subparagraph (2), any portion of the cost of natural gas at any first sale attributable to any increase in the amount of state severance taxes (as defined in section 110(c) of the NGPA) which results from a provision of state law enacted on or after December 1, 1977, shall be subject to this part.

(2) Subparagraph (1) shall not apply to any increase in state severance taxes resulting from a change in the method of computation of such tax by reason of any provision of state law enacted on or after December 1, 1977, if:

(i) As of the effective date of such change in method of computation, such increase does not result in an increase in the level of such tax, expressed as a percentage of the weighted average first sale price of natural gas produced in such state, above the percentage of such average first sale price which such tax constituted on the day before such effective date; and

(ii) Such provision of law is equally applicable to natural gas produced in the state and delivered to interstate commerce and to natural gas produced in the state and not so delivered.

(3) The price to be used in determining the weighted average first sale price for purposes of subparagraph (2) shall be the price paid at the first sale which is used by the State in administering such tax (or an imputed value, if the state uses an event other than a first sale in administering such tax).

(j) *Transactions under section 311(b) of the NGPA.* In the case of any sale under section 311(b) of the NGPA by an intrastate pipeline to an interstate pipeline or a local distribution company, any portion of the amount paid, per million Btu's, by the purchaser to the intrastate pipeline which exceeds the incremental pricing threshold for the month in which the acquisition of the natural gas occurs shall be subject to this part.

(k) *Pipeline produced gas.* (1) In the case of any natural gas produced by an interstate pipeline which is priced in its overall cost of service without regard to the cost of producing the gas, any portion of the first sale acquisition cost imputed under § 282.303 shall be subject to this part if it would have been subject to this part under paragraphs (a) through (h) had the gas been produced by an independent producer and purchased by the interstate pipeline at the imputed level.

(2) Gas produced by interstate pipelines which is treated, for rate purposes, on a cost of service basis shall not be subject to this part.

(3) Costs of gas produced by producers affiliated with interstate pipelines shall be treated as production by an independent producer and shall be subject to this part, except to the extent that different treatment has been found appropriate under the Natural Gas Act.

(l) *Surcharges paid to other pipelines.* The amount of any incremental pricing surcharge (described in § 282.504) paid by any interstate pipeline for natural gas acquired by such pipeline from another pipeline shall be subject to this part.

§ 282.302 Gas qualifying under more than one provision.

If natural gas qualifies under more than one paragraph of § 282.301, the paragraph which reflects a determination made in acordance with section 101(b)(5) of the NGPA and regulations promulgated thereunder shall be applicable for purposes of determining the portion of the first sale acquisition costs of such natural gas which shall be subject to passthrough under this part.

§ 282.303 First sale acquisition cost.

(a) *General rule.* For purposes of this part, the first sale acquisition cost of natural gas is:

(1) the price paid, per million Btu's, in any first sale of such natural gas, in the case of any natural gas produced in the United States and acquired in such first sale; or

(2) the price paid for such natural gas, per million Btu's, at the point of entry to the United States, in the case of natural gas or liquefied natural gas imported into the United States.

(b) *State severance taxes.* Any amount of state severance taxes paid at any first sale shall not be included in determining the price paid for purposes of paragraph (a).

(c) *Pipeline produced gas.* A first sale acquisition cost shall be imputed to gas produced by an interstate pipeline which is priced in its overall cost of service without regard to the cost of producing the gas. The imputed cost shall be the maximum lawful price which would have been paid under Title I of the NGPA if the gas had been produced by an independent producer. The determination of this maximum lawful price shall be made by the body which, by terms of the NGPA and the regulations promulgated thereunder, would have made the determination if the gas had been produced by an independent producer.

§ 282.304 Incremental pricing threshold.

(a) *General rule.* For purposes of this part, the incremental pricing threshold applicable for any month shall be:

(1) $1.48 per million Btu's in the case of March 1978; and

(2) in the case of any month thereafter, the amount, per million Btu's, determined under this section for the preceding month multiplied by the monthly equivalent of the annual inflation adjustment factor (as defined in section 101(a) of the NGPA) applicable for such month.

(b) *Publication.* Not later than 5 days before the beginning of each month, commencing with January, 1980, the Commission shall issue the incremental pricing threshold applicable for such month. As soon as possible thereafter, such incremental pricing threshold shall be published in the **Federal Register.**

Subpart D [Proposed in notice of proposed rulemaking issued May 11, 1979 (44 FR 29090, May 18, 1979)]

Subpart E—Incremental Pricing Accounts and Surchares

§ 282.501 General rule.

(a) Each natural gas supplier shall, on a monthly basis, accumulate in an unrecovered incremental gas costs account, as provided in § 282.502, the costs described in paragraph (a) through (k) of § 282.301 as being subject to passthrough under this part.

(b) Each interstate pipeline shall derive a reduced PGA rate for each PGA period, as provided in § 282.503.

(c) Each month, in accordance with § 282.504, each natural gas supplier shall bill incremental pricing surcharges to the sale for resale customers and the non-exempt industrial boiler fuel facilities on the supplier's system.

(1) Surcharges shall be calculated to recover the lesser of the total incremental gas costs, as defined in § 282.504, which were incurred by the supplier during the prior month or an amount equivalent to the maximum surcharge absorption capability of the supplier's customers.

(2) The maximum surcharge absorption capability of a non-exempt industrial boiler fuel facility shall be the difference between the cost to the facility for its use of natural gas, calculated on the basis of the rates of its natural gas suppliers before inclusion of incremental pricing surcharges, and the cost of that same volume of natural gas priced at the alternative fuel price ceiling applicable to the facility.

(d) Each month, in accordance with § 282.505, the amount accumulated in the natural gas supplier's unrecovered incremental gas costs account which cannot be recovered by way of incremental pricing surcharges shall be transferred from that account to account 191, Unrecovered Purchased Gas Costs.

§ 282.502 Accounting.

(a) *General rule.* For purposes of incremental pricing, each natural gas supplier shall establish an unrecovered

incremental gas costs account, an unrecovered incremental surcharges account and an incremental gas cost adjustments account.

(b) *Establishment of accounts.* (1) *Unrecovered incremental gas costs account.* Each natural gas supplier shall establish an unrecovered incremental gas costs account.

Such account shall be designated account 192.1, Unrecovered Incremental Gas Costs, for interstate pipeline following the Uniform System of Acounts, Parts 201 and 204 of this chapter. The underlying records of such account shall be maintained to permit identification of:

(i) Each purchase that gave rise to costs being charged to the account;

(ii) The paragraph of § 282.301 under which the costs associated with such purchase qualify for inclusion in the account; and

(iii) Any other charges to the account.

(2) *Unrecovered incremental surcharges account.* The unrecovered incremental surcharges account shall be designated account 192.2, Unrecovered Incremental Surcharges, for interstate pipelines following the Uniform System of Accounts, Parts 201 and 204 of this chapter. The underlying records of this account shall be maintained so as to permit identification of each incremental pricing surcharge debited to the account in accordance with paragraph (e).

(3) *Incremental gas cost adjustments account.* Each natual gas supplier shall establish an incremental gas cost adjustments account. Such account shall be designated account 805.2, Incremental Gas Cost Adjustments, for interstate pipelines following the Uniform System of Accounts, Part 201 of this chapter. Such account shall be designated account 731.2, Incremental Gas Cost Adjustments, for interstate pipelines following the Uniform System of Accounts, Part 204 of this chapter.

(c) *Debiting the unrecovered incremental gas costs account.* The unrecovered incremental gas costs account shall be debited and the incremental gas cost adjustment accoun shall be credited with:

(1) Costs described in paragraphs (a) through (k) of § 282.301 which are incurred during each calendar month; and

(2) Any other costs as permitted by order of the Commission.

(d) *Crediting the unrecovered incremental gas costs account.* (1) The unrecovered incremental gas costs account shall be credited and the incremental gas cost adjustments account shall be debited when costs included in the unrecovered incremental gas costs account are recovered by means of incremental pricing surcharges.

(2) The unrecovered incremental gas costs account shall be credited with any amount which was accumulated in the account for gas received during a calendar month but which, due to the alternative fuel price ceilings established pursuant to § 282.404, cannot be collected by way of incremental pricing surcharges to be billed during the subsequent month. Such amount may be transferred to account 191 immediately, but no later than the end of the month in which the applicable surcharges are billed.

(e) *Debiting the unrecovered incremental surcharges account.* A natural gas supplier's unrecovered incremental surcharges account shall be debited and the incremental gas cost adjustment account shall be credited with any incremental pricing surcharge which is billed to it by its supplier in accordance with a tariff sheet filed by such supplier in accordance with § 282.602.

(f) *Crediting the unrecovered incremental surcharges account.* The unrecovered incremental surcharges account shall be credited and the incremental gas cost adjustments account shall be debited for those amounts which are recovered by means of an incremental pricing surcharge.

§ 282.503 PGA reduction.

(a) *General rule.* (1) An interstate pipeline company which files purchased gas adjustment (PGA) rate changes with the Commission under authority of

§ 154.38(d) shall, each PGA period, reduce its total projected gas acquisition cost by the amount which it projects it will recover during the next PGA period through incremental pricing surcharges. The total projected gas acquisition cost, as reduced, shall be used to derive the pipeline's PGA rate for the coming PGA period in the manner prescribed in the pipeline's effective PGA provision.

(2) The amount which an interstate pipeline projects it will recover through incremental pricing surcharges during a PGA period shall be the lesser of:

(i) The costs subject to incremental pricing, as described in paragraphs (a) through (l) of § 282.301, which the pipeline projects it will incur during the coming PGA period; or

(ii) The total of the projected maximum surcharge absorption capabilities (MSAC) of each of the non-exempt industrial boiler fuel facilities directly served by the pipeline, as computed in accordance with paragraph (b), plus the total of the projected MSAC's of the pipeline's sale for resale customers, as determined by each of the customers in accordance with paragraph (c) and reported to the pipeline in accordance with paragraph (d).

(b) *Projected MSAC of a non-exempt industrial boiler fuel facility.* (1) The projected MSAC of a non-exempt industrial boiler fuel facility for a coming PGA period shall be calculated by a natural gas supplier in accordance with the following formula:

$$M = [(A_1 - R_1) V_1] + [(A_2 - R_2) V_2] + \ldots + [(A_n - R_n) V_n]$$

where:

M = Projected MSAC of the non-exempt industrial boiler fuel facility.

A = Projected alternative fuel price ceiling for the non-exempt industrial boiler fuel facility, plus taxes, as determined in accordance with subparagraph (2).

R = Projected rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the non-exempt industrial boiler fuel facility will purchase natural gas, as determined in accordance with subparagraph (3).

V = Projected volume of natural gas (at 1,000 Btu's per cubic foot) that the non-exempt industrial boiler fuel facility will purchase from the natural gas supplier and use for boiler fuel, as estimated for each of the months "1" through "n" of the PGA period.

n = Last month of the PGA period.

(2)(i) As a value for "A" for each of the months "1" through "n" of the coming PGA period, a natural gas supplier shall use the most recently established alternative fuel price ceiling applicable to the facility, plus taxes, unless the supplier elects to estimate the applicable alternative fuel price ceilings for each of the months of the PGA period. In that case, the estimated ceilings, plus taxes, may be used as values for "A".

(ii) If a local distribution company desires assistance in estimating applicable alternative fuel price ceilings for each of the months of the coming PGA period, the interstate pipeline which supplies the local distribution company shall provide such assistance.

(3)(i) *Local distribution company.* As a value for "R" for each of the months "1" through "n" of the coming PGA period, a local distribution company shall use its effective rate per million Btu's at the time of projection, plus taxes but exclusive of any incremental pricing surcharges, unless the local distribution company elects to adjust such rate to reflect general rate changes which it is known will occur during the PGA period under authority of a state or local regulatory body. If the local distribution company elects to adjust the rate, the values used for "R" may reflect the adjustments for the months of the PGA period for which the adjustments are appropriate.

(ii) *Interstate pipeline.* As a value for "R" for each of the months "1" through "n" of the coming PGA period, an interstate pipeline shall use its effective contract rate per million Btu's at the time of projection, plus taxes but exclusive of any incremental pricing surcharges, unless the pipeline elects to adjust such rate to reflect rate changes which it is known will occur during the PGA period.

(c) *Projected MSAC of a sale for resale customer.* With respect to each of its natural gas suppliers, the projected MSAC of a sale for resale customer shall be derived by adding the sum of the projected MSAC's of the non-exempt industrial boiler fuel facilities served directly by the sale for resale customer, as determined in accordance with paragraph (b), to the sum of the projected MSAC's of the customer's own sale for resale customers, as reported in accordance with paragraph (d), and multiplying the resulting total by the percentage reflecting the ratio between:

(i) The volume of natural gas (at 1,000 Btu's per cubic foot) which the customer estimates it will purchase from the supplier during the coming PGA period; and

(ii) The total of:

(A) The volume of natural gas (at 1,000 Btu's per cubic foot) which the customer estimates it will purchase from interstate pipelines;

(B) The volume of natural gas (at 1,000 Btu's per cubic foot) which is included in any of the categories specified in paragraphs (a) through (k) § 282.301 and which the customer estimates it will purchase from sources other than interstate pipelines; and

(C) If the sale for resale customer is an interstate pipeline, the estimated volume of pipeline produced natural gas (at 1,000 Btu's per cubic foot) to which a first sale acquisition cost will be imputed under paragraph (c) of § 282.303.

(d) *Reporting.*—(1) *Pipeline to request information.* Prior to the beginning of each of its PGA periods, each interstate pipeline shall request that each of its sale for resale customers report to it the customer's projected MSAC in a timely fashion.

(2) *Pipeline customers to report.* Each natural gas supplier shall respond to the requests of interstate pipelines for projected MSAC's for a coming PGA period in a timely fashion.

(iii) *Scheduling by the Commission.* In those instances where the Commission finds that natural gas suppliers have not arranged for the reporting of information in accordance with this section, the Commission shall prescribe by order an appropriate schedule for the expeditious transmission of the information necessary for interstate pipelines to make their regular PGA filings with the Commission.

§ 282.504 Incremental pricing surcharge.

(a) *General rule.* Each natural gas supplier shall include an incremental pricing surcharge, stated as a dollar amount, in its monthly bills to the non-exempt industrial boiler fuel facilities and sale for resale customers on its system. Surcharges billed to non-exempt industrial boiler fuel facilities shall be determined in accordance with paragraph (c). Surcharges billed to sale for resale customers shall be determined in accordance with paragraph (d). Such surcharges shall recover, subject to the limitation of the alternative fuel price ceilings described in § 282.404, the total incremental gas costs as defined in paragraph (b), which were incurred by the natural gas supplier during the previous month.

(b) *Definitions.* For purposes of this section:

(1) "Total incremental gas costs" means the sum of the following:

(i) the amount of the costs accumulated in a natural gas supplier's unrecovered incremental gas cost account for a period; and

(ii) any incremental pricing surcharges imposed on the natural gas supplier by its own supplier(s) for that period.

(2) "Billing month" means, for a non-exempt industrial boiler fuel facility, the period between the meter reading on or about the twentieth day of one month and the meter reading on or about the twentieth day of the following month, *provided that* for the month of January 1980, the billing month shall commence January 1, 1980.

(c) *Surcharges on non-exempt industrial boiler fuel facilities.* (1) *General rule.* The incremental pricing surcharge to be billed for the previous billing month by a natural gas supplier

for each of the non-exempt industrial boiler fuel facilities which it directly serves shall, subject to subparagraph (4), be the lesser of:

(i) The MSAC of the non-exempt industrial boiler fuel facility for the previous billing month, as determined in the manner described in subparagraph (2); or

(ii) The non-exempt industrial boiler fuel facility's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous calendar month, as determined in the manner described in subparagraph (3) of this paragraph.

(2) *MSAC of a non-exempt industrial boiler fuel facility.* (i) The MSAC of a non-exempt industrial boiler fuel facility for the previous billing month shall be determined in accordance with the following formula:

$$M = [(A - R)(V)]$$

where:

M = MSAC of the non-exempt industrial boiler fuel facility.

A = Alternative fuel price ceiling applicable to the non-exempt industrial boiler fuel facility for the billing month, plus taxes.

R = Rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the non-exempt industrial boiler fuel facility purchased gas from the natural gas supplier during the billing month.

V = Volume of natural gas (at 1,000 Btu's per cubic foot) supplied by the natural gas supplier to the non-exempt industrial boiler fuel facility for boiler fuel use during the billing month, as determined in accordance with clause (ii).

(ii) The volume of natural gas supplied by a natural gas supplier to a non-exempt industrial boiler fuel facility for boiler fuel use during a billing month shall be deemed to be the total volume of natural gas supplied to the facility during the billing month, unless the natural gas supplier serving the facility distinguishes the volumes used for boiler fuel from the volumes not so used on the basis of submeter readings. If volumes used for boiler fuel are so identified, such volumes shall be used for purposes of determining the MSAC of the non-exempt industrial boiler fuel facility in accordance with clause (i).

(3) *Pro rata share of total incremental gas costs.* A non-exempt industrial boiler fuel facility's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous calendar month shall be determined by multiplying the total incremental gas costs by a percentage reflecting the ratio between:

(i) The MSAC of the non-exempt industrial boiler fuel facility for the previous billing month, as determined in accordance with subparagraph (2); and

(ii) The sum of the MSAC's of the non-exempt industrial boiler fuel facilities on the natural gas supplier's system, as determined for the previous billing month in accordance with subparagraph (2), plus the sum of MSAC's reported to the natural gas supplier by its sale for resale customers for the previous month.

(4) *Optional billing procedures for local distribution companies.* A local distribution company may elect to bill non-exempt industrial boiler fuel facilities served by it at the level of the alternative fuel price ceilings which are applicable to such facilities.

(i) If a local distribution company bills a non-exempt industrial boiler fuel facility at the level of the applicable alternative fuel price ceiling for service during the previous billing month and the MSAC of the non-exempt boiler fuel facility for such billing month exceeds the facility's pro rata share of the total incremental gas costs incurred by the local distribution company during the previous calendar month, then such local distribution company shall either refund the excess to the facility during the month after the bill was rendered or shall make such other disposition of such amount as may be ordered by a state or local regulatory authority having jurisdiction over the local distribution company.

(ii) An election made by a local distribution company in accordance with clause (i) shall be subject to review and action by a state or local regulatory authority which has jurisdiction over such company.

(d) *Surcharges on sale for resale customers.* (1) *General rule.* The incremental pricing surcharge to be

collected by a natural gas supplier from each of its sale for resale customers shall be the lesser of:

(i) The MSAC of the sale for resale customer for the previous month, as determined by the customer in the manner described in subparagraph (2) of this paragraph and reported to the natural gas supplier pursuant to paragraph (e); or

(ii) The sale for resale customer's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous month, such share being determined in the manner described in subparagraph (3) of this paragraph.

(2) *MSAC of a sale for resale customer.* With respect to each of its natural gas suppliers, the MSAC of a sale for resale customer shall be derived by adding the sum of the MSAC's of the non-exempt industrial boiler fuel facilities served directly by the sale for resale customer, as determined for the previous billing month in accordance with subparagraph (2) of paragraph (c), to the sum of the MSAC's of the customer's own sale for resale customers, as reported for the previous month in accordance with paragraph (e), and multiplying the resulting total by the percentage reflecting the ratio between:

(i) The volume of natural gas (at 1,000 Btu's per cubic foot) purchased by the customer from the natural gas supplier during the previous month; and

(ii) The total of:

(A) The volume of natural gas (at 1,000 Btu's per cubic foot) which the customer purchased from interstate pipelines during the previous month;

(B) The volume of natural gas (at 1,000 Btu's per cubic foot) which is included in any of the categories specified in paragraphs (a) through (k) of § 282.301 and which the customer purchased from sources other than interstate pipelines during the previous month; and

(C) If the sale for resale customer is an interstate pipeline, the volume of pipeline produced natural gas (at 1,000 Btu's per cubic foot) to which a first sale acquisition cost has been imputed under paragraph (c) of § 282.303.

(3) *Pro rata share of total incremental gas costs.* A sale for resale customer's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous month shall be determined by the ratio between:

(i) The MSAC reported to the natural gas supplier by the sale for resale customer for the previous month in accordance with paragraph (e); and

(ii) The sum of the MSAC's of the non-exempt industrial boiler fuel facilities on the natural gas supplier's system, as determined for the previous billing month, in accordance with subparagraph (2) of paragraph (c), plus the sum of the MSAC's reported to the natural gas supplier by its sale for resale customers for the previous month in accordance with paragraph (e).

(e) *Reporting.*—(1) *Pipeline to request information.* Each interstate pipeline shall request that, each month, each of its sale for resale customers report its MSAC to the pipeline in a timely fashion for the monthly billing of incremental pricing surcharges.

(2) *Pipeline customers to report.* Each month each natural gas supplier shall respond to the requests of interstate pipelines for its MSAC.

(3) *Suppliers to customers.* Each month each natural gas supplier shall inform each of its sale for resale customers of the amount of the incremental pricing surcharge which will be billed to such customer. Such information shall be conveyed within sufficient time so as to enable the last customer in a chain of sale for resale customers to bill incremental pricing surcharges to its customers in a timely fashion.

(f) *Scheduling by the Commission.* In those instances where the Commission finds that natural gas suppliers have not arranged for the reporting of information in accordance with this section, the Commission will prescribe by order an appropriate schedule for the transmission of the information necessary for the monthly billing of incremental pricing surcharges.

§ 282.505 Recovery of amounts in excess of the maximum surcharge absorption capabilities.

(a) The amount accumulated in a natural gas supplier's unrecovered incremental gas costs account for gas received during a calendar month which, due to alternative fuel price ceilings, cannot be recovered through incremental pricing surcharges shall:

(1) In the case of interstate pipelines, be collected under the Commission's provisions governing recovery of unrecovered gas costs as set forth in § 154.38(d)(4); and

(2) In the case of local distribution companies, be recovered in the manner permitted by the appropriate state or local authority.

Subpart F—Filing Requirements

§ 282.601 FERC gas tariff provisions.

(a) *Incremental pricing surcharge provision.* Each interstate pipeline shall establish an incremental pricing surcharge provision in its FERC Gas Tariff. The incremental pricing surcharge provision shall provide for the pass-through of costs in accordance with the requirements of this part.

(b) *Revised PGA provision.* Each interstate pipeline shall revise its PGA provision, as established in accord with § 154.38(d), to provide for a reduced PGA rate in accordance with the requirements of this part.

(c) *Filing dates.* The incremental pricing surcharge provision and revised PGA provision shall be filed with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and serve on all parties by November 1, 1979. The provision shall become effective on December 1, 1979, unless disapproved in whole or in part by the Commission.

§ 282.602 Tariff sheets.

(a) *General rule.* (1) On or before December 1, 1979, for the period January 1, 1980 to the effective date of the pipeline's next normally scheduled PGA filing, each interstate pipeline shall file concurrently:

(i) A tariff sheet reflecting a reduced PGA rate as determined in accordance with § 282.503; and

(ii) For informational purposes only, and so labeled, a tariff sheet reflecting projected incremental pricing surcharges, as determined on the basis of data used in deriving the reduced PGA rates referenced in clause (i), for each of the non-exempt industrial boiler fuel facilities and sale for resale customers on the pipeline's system.

(2) Revisions to the tariff sheets filed pursuant to subparagraph (1) shall be filed in accordance with each interstate pipeline's normal PGA schedule, as necessary to revise the previously effective tariff sheets.

(b) *Form and filing requirements.* Any tariff sheet filed pursuant to paragraph (a) shall be subject to the provisions and requirements of Part 154 of this chapter.

(c) *Service.* The interstate pipeline which files tariff sheets pursuant to paragraph (a) shall concurrently serve copies on each sale for resale customers subject to the tariff sheets and each interested state commission.

(d) *Material to be submitted.* (1) Tariff sheets filed pursuant to paragraph (a) shall be accompanied by a report containing computations showing the derivation of the reduced PGA rate and the incremental pricing surcharges set forth in such tariff sheets.

(2) Tariff sheets filed pursuant to paragraph (a) shall be accompanied by a supplement to the statement of a pipeline's current cost of purchased gas as required by § 154.38(d).

(i) Such supplement shall identify, for the prior PGA period, each source of supply by API well identification number, contract date and FERC rate schedule number. Where multiple wells are metered through a common delivery point or where production from multiple wells is sold under a single contract, the supplement shall identify each well that produces gas which is subject to this part. Such supplement shall identify the price paid for gas from each well identified in accordance with this paragraph.

(ii) Such supplement shall show for account 192.1, for the prior PGA period:

(A) Total monthly debits to such account;

(B) Total monthly credits to such account resulting from the recovery of costs by means of incremental pricing surcharges; and

(C) The monthly amount credited to clear the account to account 191 and the date the clearing entry was made.

(iii) Such supplement shall show for account 192.2, for the prior PGA period:

(A) The incremental pricing surcharges debited to the account each month by the pipeline; and

(B) The total monthly credits to the account resulting from the recovery of costs by means of incremental pricing surcharges.

(e) *Additional information.* The Commission may, upon receipt of a tariff sheet filed pursuant to this section, require the submission of additional information as it deems necessary and appropriate.

§ 282.603 Informational filings.

(a) *General rule.* For informational purposes, each month commencing March 1, 1980, each interstate pipeline company shall tender to this Commission a statement setting forth the incremental pricing surcharge actually billed to each non-exempt industrial boiler fuel facility and sale for resale customer on its system in the preceding month.

(b) *Address.* The informational filings required by paragraph (a) shall be addressed to Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Appendix A

Federal Energy Regulatory Commission, Washington, D.C. 20426.

Docket No. RM79-14

Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas

Participation is Voluntary.

Copies of executed exemption affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Please Read Before Completing This Affidavit

Purpose

The Natural Gas Policy Act of 1978 (NGPA) provides that natural gas used as boiler fuel by any industrial boiler fuel facility will be subject to incremental pricing surcharges unless otherwise exempted. The statute also provides for certain exemptions from these incremental pricing surcharges. To be wholly or partially exempt from incremental pricing surcharges the boiler fuel must be consumed for one of the statutorily exempt uses. This affidavit serves the purpose of identifying those natural gas uses within your facility which are entitled to a full or partial statutory exemption from incremental pricing surcharges but which could not be identified as exempt through review of the records of your natural gas supplier. If a facility has not been identified as totally or partially exempt from incremental pricing surcharges through review of your natural gas supplier's records or through the filing of this affidavit in accordance with the general instructions below, all gas sold to the facility will be subject to incremental pricing surcharges.

General Instructions

If you claim an exemption from incremental pricing surcharges for all, or a portion, of the gas used by your facility which has been identified by your natural gas supplier as a potentially non-exempt industrial boiler fuel facility, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which a total or partial exemption from incremental pricing surcharges is claimed.

The original and five copies of this affidavit should be submitted to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility shall retain such records, documents and data which formed the basis for the exemption claimed on this affidavit. Definitions which may be helpful in completing this affidavit are provided below.

If you have any questions concerning this affidavit contact Mr. Warren Edmunds on (202) 275-4415.

Definitions

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(3) "Industrial facility" means any facility which primarily changes raw or unfinished materials into another form or product.

(4) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the provisions of this part in accordance with Part 282 of the Commission's rules and regulations.

(5) "Agricultural use" means any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA.

(6) "Qualifying cogeneration facility" means a cogeneration facility which meets the requirements prescribed in § —— of the Commission's rules and regulations.

(7) "School" means a facility the primary function of which is the delivery of instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the delivery of instruction.

(8) "Hospital" means a facility the primary function of which is the delivery of medical care to patients who remain at the facility. Outpatient clinics or doctor's offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(9) "Similar institution" means a facility the primary function of which is the same as the primary function of the facility to which it is compared.

1.0 Name of Company or Organization: ——

* * * * *

2.0 Name of Facility: ——

* * * * *

3.0 Address: ——

Number Street

City/Town County State Zip Code

* * * * *

4.0 Name of Natural Gas Supplier: ——

* * * * *

5.0 Did your facility, on the basis of records, documents or data in your possession, consume less than an average of 300 Mcf per day as boiler fuel during all calendar months during calendar year 1977?

(a) ☐ Yes.....Sign and return affidavit.

(b) ☐ No.....Continue to 6.0

* * * * *

6.0 Is all of the natural gas consumed as boiler fuel at your facility for an agricultural use?

(a) ☐ Yes.....Sign and return affidavit.

(b) ☐ No.....Continue to 7.0

* * * * *

7.0 Is your facility, in its entirety, any of the following:

(a) A qualifying co-generation facility?

☐ Yes ☐ No

(b) A school, hospital, or similar facility?

☐ Yes ☐ No

(c) Used for generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, sign and return this affidavit. If the answer is "no", continue to 8.0.

* * * * *

8.0 Is a portion, though not all, of the gas consumed at your facility used as boiler fuel for an agricultural use?

(a) ☐ Yes.....See "NOTICE" below.

(b) ☐ No.....Continue to 9.0

* * * * *

9.0 Is your facility, in part, but not in its entirety, any of the following:

(a) A qualifying co-generation facility?

☐ Yes ☐ No

(b) A school, hospital, or similar facility?

☐ Yes ☐ No

(c) Used for the generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, see "NOTICE" below, sign and return this affidavit. If the answer is "no" to all questions in items 5.0 through 9.0, you should not return this affidavit.

* * * * *

Notice

If you have responded affirmatively to question 8.0, the volume of natural gas used in your facility which shall be exempt from incremental pricing shall be determined on the basis of and to the extent there are submeter reading records for each billing month, as signed under oath by a responsible company official; which show the extent to which gas is consumed for an agricultural use and which are made available to the facility's natural gas supplier as required by the supplier.

If you have responded affirmatively to any part of question 9.0, the volume of natural gas which shall be exempt from incremental pricing shall be determined on the basis of and to the extent there are submeters which permit determination of the volume of exempt usage and which are available to be read by the facility's natural gas supplier.

Dated:———

Person completed this affidavit:

———

Name

———

Title

———

Phone number

Subscribed and sworn to before me this ———day of ————.

———

Notary Public

Appendix B

Federal Energy Regulatory Commission, Washington, D.C. 20426.

Docket No. RM79–14

Reaffirmation of Eligibility for Exemption From Incremental Pricing Program

Name of Company or Organization: ———

———

Address: ———

———

———— hereby affirms that the Affidavit for Exemption filed on behalf of the above-named company on ———, ——, remains accurate as of the date below.

Dated: ————

———

Authorized Official

———

Title

———

Phone number

Subscribed and sworn to before me this ———— day of ————.

———

Notary Public

¶ 32,026 Calculation of Cash Working Capital Allowance for Electric Utilities

44 F. R. 33410 (June 11, 1979).

[18 CFR Part 35]

[Docket No. RM79-49]

Calculation of Cash Working Capital Allowance for Electric Utilities

June 7, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is proposing to amend its regulations under the Federal Power Act by adding a new § 35.24. The new section sets forth the methods by which a utility filing a change in rate schedule under § 35.13 must calculate the cash working capital allowance.

DATES: Written comments must be filed by July 9, 1979. Reply comments must be filed by July 24, 1979. Replies to any Commission Staff comments must be filed by August 8, 1979.

ADDRESSES: All filings should reference Docket No. RM79-49 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:
Michael A. Coleman, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-4728.
Bonnie Cord, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capital Street, NE., Washington, D.C. 20426 (202) 275-4285.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is proposing to add a new § 35.24 to its regulations relating to the filing of rate schedules under the Federal Power Act (18 CFR Part 35). The new section would establish the formula to be used to calculate the cash working capital allowance for electric utilities.

A. Background

Cash working capital as it relates to this rule is the amount of cash needed by an electric utility to meet its operating expenses for the period during which the utility has provided services to its customers and has not yet been paid for those services. The cash working capital allowance is the amount of cash working capital which the Commission allows a utility to include in its rate base. To determine the proper cash working capital allowance for a particular utility, the Commission must determine the time period between the utility's payment of expenses incurred in the rendition of service and its receipt of payment for the service by its customers.

The Federal Power Commission, and now Federal Energy Regulatory Commission, has traditionally made this determination by application of the 45-day convention, the term given to the customary practice under which a utility is allowed one-eighth (one-eighth of a year equaling 45 days) of the utility's annual operation and maintenance expense minus purchased power expense as its cash working capital allowance. The rationale behind the 45-day convention is given in the earliest published Federal Power Commission decision employing the convention:

> Electric energy furnished by the company during the current month is billed to the customer as of the first of the succeeding month with a fifteen-day discount period. The full period between the dates of rendition of service and the payment was adopted as the period of lag and the working capital required for this period (exclusive of fuel and other supplies) was determined to be 45/365 of operating costs, * * * . (*Interstate Power Co.*, 2 FPC 71, 85 (1939).)

The 45-day convention is simple and inexpensive to apply; however, studies which have recently been submitted to the Commission by utilities and their

customers have indicated that the 45-day convention may not accurately reflect individual utilities' actual cash working capital needs. Although at the time the convention was developed it appeared to reasonably reflect actual business practices, those practices have changed in the ensuing years (*e.g.*, computerization and other improvements in billing procedures reduce the time necessary for billing and payment). Therefore, the application of the 45-day convention under current business practices may result in utilities' including in their rate bases more working cash than actually needed to meet operating expenses, thus unfairly burdening the utilities' customers.

The Commission and its staff have investigated appropriate methods for calculation of the cash working capital allowance in light of current business practices. One possible method of making the calculation is a lead-lag study. such a study takes into account all factors relating to cash working capital and determines for each the average time between the utility's payment of expenses and its receipt of revenue from its customers. Hence, such a study, if fully developed, can provide a relatively accurate picture of a utility's cash working capital requirements. However, lead-lag studies are expensive and time-consuming to perform. Thus, the Commission has determined that requiring such a study to be performed by each utility seeking a change in rate schedule would be unduly burdensome.

In its search for a reasonably accurate, yet comparatively simple, method of calculating the cash working capital allowance, the Commission recognizes that such a method will be an approximation of the actual working cash needs of individual electric utilities. However, the establishment of a rule requiring that the allowance be calculated by such a method will avoid the necessity to litigate this issue in rate proceedings, thus eliminating a great cost to ratepayers and resulting in more timely Commission decisions. Accordingly, the Commission is herein proposing to add to its regulations a new § 35.24 which would establish a formula to calculate an allowance for cash working capital to be used by any electric utility required to file cost of service statements to accompany a filing for a change in rate schedule under § 35.13(b)(4). The Commission believes that the formula is an improvement over the 45-day convention in that it takes account of current business practices and in that it makes allowances for the differing working cash needs of individual utilities. Thus, the formula provides sufficient specificity and accuracy, while eliminating the need for parties to rate proceedings to bear the time and expense burdens associated with litigation of the working cash issue.

B. Summary of the Proposed Regulation

Paragraph (a) of new § 35.24 States the general rule for the calculation of the cash working capital allowance. Subparagraph (1) provides that if an electric utility is required to file cost of service statements to accompany a filing for a change in rate schedule under § 35.13(b)(4), then the utility must calculate the cash working capital allowance according to the formulas set forth in paragraph (c). Subparagraph (2) of paragraph (a) provides that no party to a proceeding arising from a filing for a change in rate schedule under § 35.13(b)(4) may, for purposes of that proceeding, calculate the cash working capital allowance except in accordance with the formulas under paragraph (c) as required by this section.

Subparagraph (1) of paragraph (c) states that the cash working capital allowance is the average daily uncollected revenue attributable to cash expenditures for service rendered minus the average daily unpaid amounts of cash-basis expenses incurred for the service rendered. This subparagraph sets forth the general cash working capital formula, as follows:

CWC=REV—EXP,

where CWC is the cash working capital allowance, REV is the result obtained from application of the revenue formula

under subparagraph (2), and EXP is the result obtained from application of the expense formula under subparagraph (3).

Subparagraphs (2) and (3) of paragraph (c) set forth the revenue and expense formulas, as follows:

$$REV = \frac{40}{360}\left(F + L + M + AVT + RT + ITP\right), \text{ and}$$

$$EXP = \left(\frac{A}{360}\right)F + \left(\frac{10}{360}\right)L + \left(\frac{25}{360}\right)M + \left(\frac{B}{360}\right)AVT + \left(\frac{C}{360}\right)RT + \left(\frac{90}{360}\right)ITP .$$

The following discussion of the formulas is divided into three segments: (1) A general description of the formulas; (2) a discussion of the expense items that are included in the formulas and days lag applied to each expense item; and (3) a discussion of items (such as purchased power, payroll tax, depreciation, bond interest, and bank balances) that were excluded from the formulas.

1. *General description of the formulas.* The REV and EXP formulas are basically the sum of six annual expenses (F, L, M, AVT, RT, ITP), which expenses have been multiplied by that fraction of the year for which: (1) Revenue to compensate the utility for incurring each expense in the rendition of service is uncollected; and (2) each expense is unpaid. Thus, the REV formula yields an average amount of cash which is uncollected by the utility between the time it provides service to its customers and the time at which it receives payment for that service. That amount is uncollected because utilities do not receive payment from customers simultaneously with the rendition of service.

The EXP formula yields an average amount of cash which is not needed by the utility during the time between rendition of service and payment of the expenses attributable to such service, but which would otherwise be needed to pay expenses simultaneously with the incurrence of the expenses in providing service. That amount is not immediately needed because utilities generally pay for expenses incurred in the rendition of service to their customers at dates after the incurrence of the expenses.

To ensure comparability of the formulas, the formula amounts are stated to reflect uncollected revenue and unpaid expenses from the same point in time; that is, the formulas are referenced to a common benchmark, the rendition of service by the utility, so that the resultant net effect of uncollected revenue and unpaid expenses can be calculated. Hence the dollar amount resulting from application of the REV formula minus the dollar amount resulting from the application of the EXP formula gives CWC, the average amount of cash working capital needed by the utility to pay for expenses before it receives payment from its customers. Should the utility pay for expenses after it receives payment from customers, the application of the REV and EXP formulas will result in a negative CWC amount; that is, such pattern of revenue collection and expense payment provides a source of cash working capital to the utility.

2. *Expense items included in the formula and the days lag applied to each.* The commission has analyzed working cash requirements in light of all operating expenses (not limited to operation and maintenance expenses as in the present 45-day convention) and has determined that six cash-basis expenses have a significant impact upon working cash needs. The six expenses are fossil fuel, labor, other operation and maintenance, ad valorem taxes, revenue taxes and income taxes payable. In the formulas, these expenses are annual figures for the test period (as defined in § 35.13(b)(4)(iii)) and are represented by F, L, M, AVT, RT, and ITP, respectively.

As discussed above, each of these annual expense figures is multiplied by that franction of the year during which the expense is unpaid or revenue to compensate the utility for incurring the expense is uncollected.

With respect to the REV formula, since customers make one payment per billing cycle which includes payment for the six expenses in the formulas, the fraction of the year during which the revenue to compensate the utility for incurring the expenses is uncollected is the same for all six expenses, and thus each of the six annual expenses is multiplied by the same fraction. That fraction is 40/360 and is derived from the following analysis.

The fraction of the year during which revenue is uncollected, the revenue lag, is the time period from the midpoint of the serivce period to the average date of payment by the customer. "Service period" is the time interval for which the utility customarily measures the service rendered to its customers and is considered to be 30 days on the average. For purposes of analysis, the revenue lag may be broken down into three periods: rendition of service, bill preparation and bill payment. Assuming a constant rendition of electric service during a 30-day billing cycle, service is provided, on the average, 15 days prior to the end of the service period. The revenue lag, therefore, consists of this 15-day period plus allowances for bill preparation and bill payment.

In determining reasonable time periods for bill preparation and bill payment, the Commission has considered the great amount of control a utility exercises over the time taken by these two activities, by virtue of the fact that utility management determines the timing of meter readings, bill preparation and presentation, and the establishment of the date by which bills must be paid. The Commission has determined that a time allowance of 10 days for meter reading, bill preparation, and mailing is reasonable, with a 15-day period thereafter for bill payment. The Commission believes that shorter time allowances would impose difficulties on utility workload management and would be burdensome to wholesale customers; while larger time allowances, resulting in an increase in working cash requirements, are not necessary in view of billing procedure options available to a utility.

Therefore, the revenue lag is 40 days (15 days to the midpoint of the service period, plus 10 days for bill preparation, plus 15 days for bill payment). Accordingly, each annual expense in the REV formula is multiplied by 40/360.

With respect to the EXP formula, each of the six expenses must be multiplied by a different fraction, because the utility's payment pattern is different for each expense. Each expense is discussed separately below. For purposes of calculation of the cash working capital allowance, the expense lag is the time period between the date on which the utility provides service (giving rise to the expenses) and the date on which it pays the expense.

a. *Fossil fuel (F).* Due to its large share of total operating expenses, payment for fossil fuel purchases has a significant impact upon cash working capital needs. The expense lag associated with the fossil fuel expense is dependent upon billing and payment procedures employed by the fuel suppliers, with considerable variation to be anticipated, depending on such factors as quantities purchased, frequency of deliveries, available on-site storage facilities for each type of fuel used, and type of purchase (contract or spot). The expense lag is also dependent upon the fuel mix used for generating purposes, which varies from utility to utility. Accordingly, an analysis of fossil fuel purchases and payment patterns is needed for each utility in order to obtain a reasonably accurate measure of working cash needs resulting from fossil fuel purchases. Since utilities have readily available data with respect to their fuel purchases, the expense lag, A, for the fossil fuel expense is to be determined by the utility in accordance with paragraph (d) or (e) of the proposed rule, as discussed below. Thus, in the EXP formula, the annual fossil fuel

expense is multiplied by the fraction A/360.

b. *Labor expenses (L).* The effect of the payment pattern for wages and salaries on cash working capital requirements is expected to vary little from utility to utility. While the actual combination of weekly, semi-monthly and monthly wage and salary payments may vary among utilities, the expense lag is not significantly different, as illustrated in the following examples. (Weekly wages are generally paid one week after the end of a pay period. Semi-monthly salaries are generally paid at mid-month and the last day of the month. Monthly salaries are usually paid on the last day of the month.)

	(1) Percent employees	(2) Expense lag	(3) Weighted expense lag [(1) × (2)]
Example 1:			
Weekly	75	10.5	7.875
Semimonthly	25	7.5	1.875
Monthly	0	15.0	0.000
Total	100		[1]9.750
Example 2:			
Weekly	60	10.5	6.30
Semimonthly	30	7.5	2.25
Monthly	10	15.0	1.50
Total	100		[1]10.05

[1] Average expense lag.

Accordingly, the Commission believes that 10 days is a reasonable expense lag for labor expense. Thus, in the EXP formula, the fraction by which the annual labor expense is to be multiplied is 10/360.

c. *Other operation and maintenance expenses (M).* Other operation and maintenance expenses includes all operation and maintenance expenses except fuel, purchased power and labor expenses. Although the other operation and maintenance expense category includes a variety of items, operation and maintenance supplies are usually the predominant expense amounts. Major maintenance tends to be seasonal, which suggests that the expense lag for the required materials and supplies should be determined for the 12-month test year, rather than on an average monthly basis. However, since the total amount of dollars in this expense category is typically less than 20% of the total of all categories, and since there is a wide variety of items other than materials and supplies in this category, the Commission believes that an expense lag of 25 days will yield a reasonable result. Twenty-five days is twice-monthly expense invoicing, resulting in a 7.5 day average lag at invoice date, plus 15 to 20 days for invoice preparation and expense payment. Therefore, in the EXP formula, the fraction by which the annual other operation and maintenance expense as multiplied is 25/360.

d. *Ad valorem taxes (AVT) and revenue taxes (RT).* Ad valorem taxes are those taxes which are based upon an assessment or valuation of property (tangible and intangible) owned by a utility (*e.g.*, property taxes). Revenue taxes are those taxes which are based upon the level of revenue earned by a utility (*e.g.*, gross receipts taxes). Ad valorem taxes are typically less than 10% of total operating expenses. Revenue taxes are applicable only in certain jurisdictions, and, where present, they are not usually a large component of operating expenses. These facts might suggest that therse taxes are not a significant consideration in cash working captial evaluation; however, tax payment schedules frequently involve lengthy lag periods, thereby giving the taxes added weight in determining average cash availability for working capital.

The payment lag for ad valorem taxes and revenue taxes fluctuates widely from utility to utility because each company is subject to localized assessments and payment schedules. Some expenses are paid in advance while others are paid at varying lagging intervals. A wide range of payment dates within an individual utility's tax items in these categories may occur due to the difference in the taxes assessed among sectors of the service territory of the utility. Therefore, in order that suitable expense lags for ad valorem

and revenue taxes be calculated, the expense lag for these items is to be determined by the utility in accordance with paragraph (d) or (e) of the proposed rule, as discussed below. Thus, in the EXP formula, the annual ad valorem tax expense and the annual revenue tax expense are multiplied by the fractions B/360 and C/360, respectively.

e. *Income taxes payable (ITP).* The final expense item included in the formulas is income tax payable, which is income tax allowable under § 35.13(b)(4)(iii) (Statement J) less any deferred taxes. Income taxes payable is considered to be the appropriate amount for which working cash requirements are to be analyzed, because income tax allowable includes deferred taxes which do not require a cash outlay during the test period. Income taxes payable would include state as well as federal income taxes, because state income tax payment procedures generally reflect payment patterns for federal income taxes. It is noted that state income tax expense is a relatively small portion of total operating expenses.

A reduction in the amount of working cash allowed is necessary to reflect the availability of funds resulting from receipt of revenues earmarked for income taxes in advance of the payment of the taxes. Payments of estimated federal income taxes in the amount of 25% of the calculated estimated taxes for the year are due on the fifteenth day of the fourth, sixth, ninth and twelfth months of the current tax year. I.R.C. § 6154. However, the total of the estimated taxes paid by a utility during the current tax year may be as little as 80% of the total taxes payable for the taxable year without an underpayment penalty being assessed against the company. I.R.C. § 6655 (d) and (e). Under such a payment procedure, the remaining 20% of taxes due may be paid in equal installments on the fifteenth day of the third and sixth months following the end of the taxable year.

The Commission believes that utility companies attempt to conform their income tax payments with these latter provisions. Such a payment schedule results in the payment of 20% of total income taxes payable on each of the four estimated tax payment dates during the taxable year and the payment of 10% of the total income taxes payable on each of the two dates during the succeeding year. From such a payment schedule, illustrated in the following table, an expense lag of ninety days has been calculated.

Date paid	Percent paid	Days before year-end	Average weighted days before year-end
Month, Day, and Year:			
4 15 current	20	255	51.0
6 15 current	20	195	39.0
9 15 current	20	105	21.0
12 15 current	20	15	3.0
3 15 following	10	−75	−7.5
6 15 following	10	−165	−16.5
Total	100		90.0

(Average number of days from midpoint of each service period to year-end) − (average weighted days before year-end) = (average days lag from the midpoint of each service period):

180 − 90 = 90

Therefore, the Commission believes that a ninety-day expense lag for income taxes payable is appropriate. Accordingly, the fraction in the EXP formula by which the annual income tax payable expense is multiplied is 90/360.

3. *Items excluded from the formulas.* Several other items have been considered for inclusion in the REV and EXP formulas, but for reasons discussed below have not been included.

a. *Purchased power expense.* Historically, purchased power expense has been excluded from the calculation of a utility's working cash requirement. This exclusion has been based upon the assumption that lags in payment for purchased power transactions by the utility to the supplier of the power were equal to the lag in revenue receipt by the utility.

The purchase of electric power by one utility from another is similar in nature to receipt of electric service by wholesale customers from a utility. Therefore, billing and payment procedures associated with purchased power transactions should conform closely to those associated with the rendition of electric service to wholesale customers. In recognizing that providing electric service and purchasing electric power and energy are but the selling and buying positions related to the exchange of a homogeneous commodity, the components of an expense lag associated with purchased power transactions (service period, bill preparation period, and bill payment period) should equal the components comprising the revenue lag assigned to the rendition of service.

Since the Commission is proposing to establish forty days as the appropriate revenue lag associated with the rendition of electric service, purchased power expense will be assigned a forty-day expense lag. The assignment of equal revenue and expense lags to purchased power expense eliminates the need to include this expense item in the formula reflecting the effects of purchased power expense on working cash needs. Therefore, the Commission is proposing to exclude purchased power expense from the cash working capital formulas.

b. *Payroll tax.* Payroll tax has not been included in the formulas because the Commission believes that this expense does not have a significant impact upon cash working capital. In addition, payroll taxes are not incurred throughout the entire year since such taxes are assessed up to certain employee income levels and, therefore, impact less upon working cash needs as the year progresses.

c. *Depreciation and amortization.* Depreciation and amortization expenses (including nuclear fuel expense Account 518), although operating expense components, represent recoveries of investments not requiring a current outlay of cash. Therefore, such items need not be included in a calculation of cash working capital requirements.

d. *Bond interest and preferred stock dividends.* The Commission considered reductions to the cash working capital allowance to reflect the availability of funds for payment of bond interest and preferred stock dividends as sources of working cash. In this connection, the Commission observes that common and preferred equity return are due the utility when service is rendered; however, the proposed rule does not provide for a cash allowance to recognize that the equity and preferred return components of revenue are not received until forty days after service is rendered. Consistent with this treatment, the proposed rule does not require the utility to utilize the interest component of return as working cash, even though the interest may not be paid to the bondholders until after the related revenue is received by the utility. Further, since as stated above both common and preferred equity return belong to the company when service is rendered, the related revenues subsequently received are not available as working cash.

e. *Minimum balances and compensating balances.* Minimum balances are bank balances which may be required to secure bank account services. The Commission does not believe that such minimum balances are properly considered to be part of cash flow requirements for day-to-day operations. If in fact a utility is required to maintain minimum bank balances under terms of written agreements, the utility may make a separate claim for a rate base allowance therefor. Such claims will be considered as they arise in cases which come before the Commission.

Compensating bank balances are balances which may be required to compensate a lending institution for extending a line of credit necessary to provide for short-term loans. The Commission has previously indicated that any need for compensating balances is more appropriately considered either in the rate of return allowance or in a decision fixing the proper accrual rate for allowance for funds used during construction. (*Carolina Power and Light Company*, Opinion No. 19, Docket No. ER76-495, issued August 2, 1978). Therefore, neither minimum balances nor compensating balances are included in the cash working capital formulas.

Calculation of Expense Lags To Be Determined by the Utility

Paragraphs (d) and (e) of the proposed rule set forth the methods for determining the expense lags for fossil fuel, ad valorem tax, and revenue tax expenses. Consistent with the method used by the Commission to derive the fixed expense lags for the other expense items included in the formulas, the determination of expense lags for fossil fuel, ad valorem tax and revenue tax expenses must be correlated with the same reference point used to determine the revenue lag for those expenses (*i.e.*, the midpoint of the service period), so that both the expense lag and the revenue lag reflect intervals from the same point in time. If this method is not applied, the net effect of the lags on the cash working capital calculation would be distorted.

Paragraph (d) provides that for goods or services received, or taxes assessed, at intervals of one service period or less, the expense lag is the weighted average of the number of days which the expense item is paid after the end of the service period, plus 15 days. The 15 days is added to the weighted average number of days calculated to express the length of the expense lag from the midpoint of the service period (the point of commonality with the revenue lag). This method for calculating the expense lag is actually a shortened and simplified version of the method described in paragraph (e) and is applicable only to items which are received continuously or at very short intervals.

Paragraph (e) sets forth the method of calculating the expense lag for goods and services received, or taxes assessed, at intervals, not necessarily uniform, greater than one service period, which therefore must be averaged over the entire test year. In this case the expense lag is the test period weighted average of the number of days before year-end that payment is made for such expense items, subtracted from 180 days. The 180 days represents the average number of days from the midpoint of each of the twelve monthly service periods to year-end. The subtraction of the weighted average number of days before year-end from 180 days relates the expense lag to the midpoint of each service period (*i.e.*, the point of commonality with the corresponding revenue lag for that period).

If Period II is the test period in accordance with § 35.13(b)(4)(iii), and if Period II data are inadequate for purposes of calculating the average days lag in payment of expenses under paragraph (d) or (e), then paragraph (f) provides that Period I data are to be used to calculate the expense lag under paragraph (d) or (e). Paragraph (f) further provides that, if Period I data are used under this paragraph, the utility must submit a statement explaining why the Period II data are inadequate for purposes of calculation under paragraph (d) or (e).

C. Waiver of the Rule

The Commission feels that the proposed formula for the cash working capital allowance provides sufficient flexibility to adequately reflect the cash working capital needs of individual utilities, and thus expects that the formula would be used in all cases. However, in order to provide for the possibility that a particular utility or its

customers may suffer undue hardship as a result of application of the formula, the Commission notes that waiver of the rule may be requested in accordance with § 1.7 of the Commission's rules of practice and procedure. The Commission specifically requests comments as to the standards that should be applied to determine if a waiver should be granted.

D. Impact of the Rule

In order to aid the Commission in determining the impact of the proposed rule on the industry, the Commission requests utilities, their customers, and other members of the public to comment on the expected impact of the rule.

Specifically, comments should indicate the estimated reduction in costs incurred by parties to a rate proceeding, which reduction would result from the elimination of the cash working capital allowance as an issue to be litigated in such a proceeding. Individual utilities are also requested to specify the amount and percentage of increase or decrease in the utility's jurisdictional rate base and revenue requirements which would result from application of the proposed rule to a recent, recorded twelve-month period, as compared to: (1) Application of the historical 45-day convention (one-eighth of operation and maintenance expenses exclusive of purchased power expenses); and (2) no cash working capital allowance. Additionally, the Commission requests that individual utilities specify the increase or decrease in administrative costs which would be incurred by the utility as a result of application of the proposed rule, as compared to: (1) The historical 45-day convention; and (2) a fully developed and reliable lead-lag study.

E. Alternative to the Proposed Rule

As an alternative to the formulas proposed in this rule and discussed above, the Commission specifically requests comments on the establishment of a cash working capital formula reflecting a fixed number of days allowance similar to the 45-day allowance historically used in the 45-day convention. Such comments should address: (1) The appropriate number of days allowance and the expense base to which such figure is to be applied; (2) the advantages and disadvantages of using a formula reflecting a fixed number of days allowance, in terms of resources dedicated to the calculation of working cash requirements; and (3) whether the distortion of cash working capital needs calculated under a fixed number of days allowance, when compared to actual working cash requirements, has a significant impact upon a utility's revenue requirement.

F. Public Comment Procedures

Interested persons may participate in this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 925 North Capitol Street, NE., Washington, D.C. 20426, on or before July 9, 1979. Because of the complexity and importance of the issues presented by the rulemaking, the Commission intends that those participating in this proceeding should be able to examine and reply to initial comments made in response to this notice. Such reply comments must be submitted on or before July 24, 1979. The Commission Staff may submit comments, which shall be available to the public on or before July 24, 1979. If Staff submits comments, notice will be given, and interested persons may reply to the Staff comments on or before August 8, 1979.

Each person submitting a comment should include his or her name and address, identify the notice (Docket No. RM79-49) and give reasons for any recommendations. Comments should also indicate the name, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and fourteen conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public

inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

(Federal Power Act, *as amended*, 16 U.S.C. 791, *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,

Secretary.

1. Part 35, Subchapter B, Chapter I of Title 18, Code of Federal Regulations, is amended in the table of contents by adding in the appropriate numerical order a new section number and heading to read as follows:

PART 35—FILING OF RATE SCHEDULES

Sec.

* * * * *

35.24 Calculation of cash working capital.

* * * * *

2. Part 35, Subchapter B, Chapter I of Title 18, Code of Federal Regulations, is amended by adding a new § 35.24 to read as follows:

§ 35.24 Calculation of cash working capital.

(a) *General rule.*—(1) *In a filing for change in rate schedule.* Any electric utility which is required to file cost of service statements to accompany a filing for a change in a rate schedule under § 35.13(b)(4) must calculate the cash working capital allowance by applying the formulas under paragraph (c) of this section to the specified test period expenses submitted by the utility.

(2) *In a proceeding arising from a filing of change in rate schedule.* No party to a proceeding arising from a filing for a change in rate schedule under § 35.13(b)(4) may calculate the cash working capital allowance, for purposes of that proceeding, except in accordance with the formulas under paragraph (c) of this section as required by this section.

(b) *Definitions.* For purposes of this section:

(1) "Test period" means either Period I or Period II in accordance with the requirements of § 35.13(b)(4)(iii);

(2) "Service period" means the time interval for which the utility customarily measures the service to be rendered to its customers under the proposed rates (*e.g.*, 30 days for service rendered monthly).

(c) *Formulas.*—(1) *Cash working capital.* The cash working capital allowance is the average daily uncollected revenue attributable to cash expenditures for service rendered minus the average daily unpaid amounts of cash-basis expenses incurred for service rendered. The cash working capital allowance (CWC) is computed by subtracting the result obtained from application of the expense formula under subparagraph (3) from the result obtained from application of the revenue formula under subparagraph (2). Cash working capital is represented by the formula:

CWC = REV − EXP.

(2) *Revenue formula.* The average daily uncollected revenue attributable to cash expenditures for service rendered is one-ninth (40/360) of the sum of specified components of test period revenue (which components are specified in the following formula), and is represented by:

$$REV = \frac{40}{360} (F + L + M + AVT + RT + ITP),$$

where

REV = the average daily uncollected revenue attributable to specified cash expenditures for service rendered,
F = test period fossil fuel expense,
L = test period wages and salaries (labor) expense,
M = test period operation and maintenance expenses other than fuel, purchased power and labor expenses,
AVT = test period ad valorem taxes,
RT = test period revenue taxes, and
ITP = test period income taxes payable (based on proposed return on rate base).

(3) *Expense formula.* The average daily unpaid amounts of cash-basis expenses incurred for service rendered is the sum of specified items of test period expense (which items are specified in the following formula), each item multiplied by the ratio to 360 days of the average time in days between rendition of electric service by the utility and payment of the expense item amounts attributable to such service, and is represented by:

$$EXP = \left(\frac{A}{360}\right)F + \left(\frac{10}{360}\right)L + \left(\frac{25}{360}\right)M + \left(\frac{B}{360}\right)AVT + \left(\frac{C}{360}\right)RT + \left(\frac{90}{360}\right)ITP,$$

where

F, L, M, AVT, RT and ITP are defined as in subparagraph (2),
EXP = the average daily unpaid amounts of specfied cash-basis expenses incurred for service rendered,
Q = average days lag in payment for fossil fuel purchases, computed in accordance with paragraph (d) or (e) of this section, whichever is appropriate,
B = average days lag in payment of ad valorem taxes, computed in accordance with paragraph (d) or (e) of this section, whichever is appropriate,
C = average days lag in payment of revenue taxes, computed in accordance with paragraph (d) or (e) of this section, whichever is appropriate.

(d) *Days lag relating to one service period.* Except as provided in paragraph (f) of this section, for goods or services received, or taxes assessed, at intervals of one service period or less, the average days lag in payment of expenses is the test period weighted average of the number of days after the end of the service in which receipt occurred or assessment was made to the date of cash disbursement in payment for such expenses, plus 15 days.

(e) *Days lag relating to more than one service period.* Except as provided in paragraph (f) of this section, for goods or services received, or taxes assessed, at intervals greater than one service period, the average days lag in payment of expense is the test period weighted average of the number of days before year-end that cash disbursement is made in payment for such expenses, subtracted from 180 days.

(f) *Days lag data.* If Period II is the test period in accordance with § 35.13(b)(4)(iii), and if Period II data are inadequate for purposes of calculating the average days lag in payment of expenses under paragraph (d) or (e) of this section, then Period I data shall be used in the calculation under paragraph (d) or (e) of this section. Any utility which calculates average days lag in payment of expenses in accordance with this paragraph shall also file with the Commission a statement giving the reasons why the Period II data are inadequate for purposes of calculation under paragraph (d) or (e) of this section.

¶ 32,027 Ceiling Prices; High-Cost Natural Gas

44 F. R. 34969 (June 18, 1979).

[18 CFR Part 271]

[Docket RM79-44]

Ceiling Prices; High-Cost Natural Gas

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) issued a notice of proposed rulemaking setting forth proposed definitions for natural gas produced from geopressured brine, from coal seams, and from Devonian shale.

DATES: Comments should be filed by July 16, 1979.

ADDRESSES: All findings should reference Docket No. RM79-44 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Philip Yates, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4212.

On December 1, 1978, the Federal Energy Regulatory Commission issued Interim Regulations in Docket No. RM79-3 implementing the Natural Gas Policy Act of 1978 (NGPA) (43 F.R. 56448). Subpart G of Part 271 set forth regulations implementing section 107(a) of the NGPA, to provide incentive prices for deep, high-cost natural gas.

Section 107(b)(2)-(4) also authorized the Commission to establish incentive prices for gas from geopressured brine, occluded natural gas produced from coal seams, gas from Devonian shale, as well as gas produced from other conditions which have been determined by the Commission to present extraordinary risks or costs. However, due to statutory deadlines imposed by the NGPA, the Commission did not promulgate regulations to implement section 107(b).

The Commission believes that precise definitions for Section 107(c)(2) through (4) are required; i.e., natural gas "produced from geopressurized brine," "from coal seams," and "from Devonian shale." Pursuant to section 121(b) of the NGPA, these categories will no longer be subject to price regulation after the effective date of the incremental pricing rule required by section 201 of the Act. This proposed rule suggests definitions for these categories which would be used to implement the deregulation provisions as well as for pricing determinations if incentive prices for these categories are established. We specifically invite comments on these definitions.

The procedures to be used to determine whether or not gas is subject to the deregulation provisions of section 121(b) of the NGPA will be similar to those now governing determinations of eligibility for prices under sections 102, 103, 107, and 108 of the NGPA. More specifically, applicants will make filings with the appropriate jurisdictional agency for a determination which will be subject to Commission review. Accordingly, notice is hereby given that the Commission intends to prescribe filing requirements similar to those established for other categories in Subpart B of Part 274. Comments are solicited on the specific documents, oath statements, etc. which should be submitted to support an application for determination for the categories covered by this proposal. The Commission will review these submissions and promulgate the filing requirements together with the appropriate definitions.

Interested persons are invited to submit written comments on the proposed regulations to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments

should reference Docket No. RM79–44 on the outside of the envelope and on all documents submitted to the Commission.

Fifteen (15) copies should be submitted. All comments and related information recevied by the Commission by July 16, 1979, will be considered prior to the promulgation of the final regulations.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.* Public Utility Regulatory Policies Act of 1978, P.L. 95–617, Natural Gas Policy Act of 1978, P.L. 95–621, Department of Energy Organization Act, P.L. 95–91, E.O. 12009, 43 FR 46267).

In consideration of the foregoing, it is proposed to amend Part 271 of subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

1. Subpart G of Part 271 is amended by adding the following sections:

§ 271.710 Definition of "natural gas produced from geopressured brine."

Natural gas produced from geopressured brine" means: natural gas dissolved insubsurface brine aquifers with reservoir geopressures substantially in excess of normal saltwater hydrostatic pressures, such geopressures being due, in part, to the formation waters bearing a portion of the weight of the sedimentary over overburden.

§ 271.720 Definition of "occluded natural gas produced from coal seams."

"Occluded natural gas produced from coal seams" means: natural gas released during a mechanical degradation process from entrapment between the seams and in the micropores of beds of coal.

§ 271.730 Definition of "natural gas produced from Devonian shale."

Natural gas "produced from Devonian shale" means: natural gas produced from the fractures, micropores and bedding planes of shales deposited during the Paleozoic Devonian Period as generally found in the subsurface of the Applachian Basin and in surface outcrops around its periphery. For the purpose of this definition, Devonian shale is defined as that shale stratigraphic interval that lies between the base on the Mississippian Berea Sand or, if absent, the base of the Osage Series, and the top of the Onondaga limestone formation or its chert equivalent, the top of the Hunton group of carbonates.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

¶ 32,028 Qualification of Small Power Production and Cogeneration Facilities Under Section 201 of the Public Utility Regulatory Policies Act of 1978

44 F. R. 38872 (July 3, 1979).

[18 CFR Part 292]

[Docket No. RM79-54]

Proposed Regulations Providing for Qualification of Small Power Production and Cogeneration Facilities Under Section 201 of the Public Utility Regulatory Policies Act of 1978

Issued June 27, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: These regulations establish rules under which small power production and cogeneration facilities may be certified as qualifying facilities under Section 201 of the Public Utility Regulatory Policies Act of 1978.

DATES: Comments by August 1, 1979.

ADDRESS: All comments to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (Reference Docket No. RM79-54).

FOR FURTHER INFORMATION CONTACT:

Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 275-0423.
Bernard Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 275-4770.

Issued June 27, 1979.

Section 201 of the Public Utilities Regulatory Policies Act of 1978 (PURPA) mandates that the Commission prescribe rules under which small power production facilities and cogeneration facilities can obtain "qualifying" status.

Section 201 of PURPA [1] defines a "small power production facility" as a facility which:

(1) produces electric energy solely by the use, as a primary energy source of biomass, waste, renewable resources, or any combination thereof; and

(2) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission) is not greater than 80 megawatts.

A cogeneration facility is defined as a facility which produces electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes.[2]

A cogeneration or small power production facility may be deemed "qualified" if it is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration or small power production facilities), and if it meets such requirements as the Commission may prescribe, such as fuel use, fuel efficiency, reliability and minimum size.

In this notice of proposed rulemaking the Commission sets forth proposed requirements for qualifying cogeneration and small power production facilities and procedures by which such facilities may obtain qualification. Subsequent rulemaking proceedings will implement the provisions of Section 210 of PURPA.

A qualifying facility may be exempted from the Federal Power Act, the Public Utility Holding Company Act, and from State laws and regulations. Section 210(a) of PURPA requires that the Commission prescribe such rules as it finds necessary to encourage cogeneration and small power

[1] Section 3(17)(A) of the Federal Power Act.

[2] Section 3(18)(A) of the Federal Power Act.

production, including rules requiring electric utilities [3] to offer to sell electric energy to and purchase electric energy from qualifying small power production and cogeneration facilities.

Under Section 210(b), the Commission's rules must insure that, in requiring any electric utility to purchase electric energy from qualifying facilities, the rates for such a purchase must be "just and reasonable to the electric consumer of the electric utility", "in the public interest," non-discriminating against qualifying facilities, and shall not exceed the incremental cost to the electric utility of alternative sources. Finally, under Section 206(c)(3) of the Natural Gas Policy Act of 1978 (NGPA), the Commission may exempt qualifying cogeneration facilities from the incremental pricing provision of the NGPA.

Purpose of the Proposed Requirements and Procedures

The Commission believes that the intent of § 201 and § 210 of PURPA is to Encourage the development or better utilization of energy resources through cogeneration and small power production. These provisions of PURPA attempt, among othr purposes, to assure entreprenurial opportunities to sell electricity to electric utilities, when such electricity is generated through use of renewable energy sources or better use of industrial process heat. They reflect a belief that improved energy resource utilization may be accomplished with projects based on unconventional technologies or using small unit sizes which might not be developed by electric utilities. The provisions are not intended, however, to require the rate payers of a utility to subsidize cogenerators or small power producers.

It is the commission's view that an ojective of the qualifying requirements is to limit the benefits of the qualifying designation to facilities which represent serious and significant efforts to improve energy resource utilization. Moreover, qualifying facilities must be suitable for interconnected operation with electric utility systems and must make effective use of resources.

Any specific requirements of our regulations will necessarily reflect the current state of the the art, and the commission recognizes the need to consider facilities of novel character as well as to provide for operation of experimental and developmental facilities. Consequently, the proposed regulations contain a provision for granting qualifying status to facilities which might not otherwise qualify, if the commission determines that granting such status is in the public interest.

Scope of the Proposed Rules

In this rulemaking the Commission proposes to deal only with the determination of qualifying status under Section 201 of PURPA. Subsequent rulemakings will implement the PURPA provisions regarding terms and conditions for sale and purchase of electricity by qualifying facilities, including the rates for such transactions, and the provisions for exemption from some forms of electric utility regulation.

Summary of the Proposed Regulations

§ 292.201 *Scope.*

The proposed new § 292.201 of the Commission's Regulations states that the section applies to the certification of small power production and cogeneration facilities for qualifying status.

§ 292.202 *Application for certification of qualifying status.*

Subparagraph (a) provides that any person seeking qualifying status must file an application pursuant to this section. The Commission believes that

[3] Section 3(22) of the amended Federal Power Act defines "electric utility" as "any person or State agency which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency." The definition includes intrastate utilities which are not "public utilities" under Section 201(b) of the Federal Power Act.

many potential problems between applicants for certification of qualifying status and affected electric utilities may be eliminated by the initiation of informal discussions between the applicant and the affected utility. In order to insure that an applicant has considered the suitability of his facility for interconnected operation, we propose to require that the applicant initiate discussions with affected utilities, and submit a summary of these discussions with his application for certification. This requirement appears in paragraph (b).

Paragraph (c) sets forth the contents of an application for certification. The application must contain technical information describing the facility, a summary of discussions between the applicant and affected electrical entities, and a description of the equity ownership of the facility.

Paragraph (d) sets forth requirements specifically applicable to small power production facilities. The applicant is required to submit information indentifying the primary energy source as one of the energy sources which qualifying small power production facilities are permitted to use by section 3(17)(A)(i) of the Federal Power Act. Generally, applicants are required to supply the location of the facility in relation to other qualifying small power production facilities owned by the applicant and using the same energy resource. This subparagraph provides information needed to implement the power production capacity requirement of section 3(17)(A)(ii) that qualifying small power production facilities located at the same site not exceed 80 megawatts.

Paragraph (e) sets forth additional requirements for applications for cogeneration facilities. In addition to the information acquired under § 292.202(c), applications for certification as qualifying cogeneration facilities must contain information set forth describing the energy input and energy output of the facility in both the heat engines and theremal processes.

§ 292.203 *Notice.*

This section requires an applicant for qualifying status to serve notice of the application upon any electric utility with which the applicant proposes to operate in coordination, and to any state regulatory body with jurisdiction over that entity.

§ 292.204 *Protests.*

This section provides that any entity served with notice under § 292.203, or any other interested party may file a protest to the application for certification. The protest must be filed within 30 days of the service of notice of application. Any person filing a protest is required to serve a copy of the protest on the applicant.

Subparagraph (b) provides that the applicant may file an answer to the protest. Such an answer must be filed within 15 days of the filing of the protest and must be served on the party filing the protest.

§ 292.205 *Qualifying requirements for small power production facilities.*

Section 292.205 sets forth qualification requirements for small power production facilities. Paragraph (a) sets for the requirement that the primary energy source for a qualifying small power production facility must be biomass, waste, renewable resources or any combination thereof. The statement on the part of the managers which accompanies the Conference Report of PURPA states that the definition of small power production facility includes solar electric systems, wind electric systems, systems which produce electric energy from wast or biomass, electric energy storage systems, and hydroelectric facilities for existing dams. It also states that the term "waste" includes wood and liquid or solid waste.

For the purpose of the regulations, the term "biomass" means plant materials which are obtained from cultivation, or harvested from naturally occurring vegetation without significant depletion of the resource. The term "waste" covers municipal, agricultural, and

industrial wastes and includes any byproduct materials of any operation for which market value is less than disposal cost. Waste may be solid, liquid, or gaseous. Municipal sewage sludge would be a qualifying fuel under this definition. Manure and cornstalks are examples of qualifying agricultural wastes. Wood derived waste and debris from sawmill, lumbering, or pulp mill operations would qualify as bilogically derived industrial wastes.

A fuel (such as methane) which is conventionally derived from fossil sources would be a permissible primary fuel if it is obtained from biomass or waste as defined above.

The term "renewable resource" means any application of solar, wind, or geothermal energy. Biomass also may be a renewable resource, but fossil fuels are not. Electric energy storage facilities such as electro-chemical systems, flywheels, or pumped storage units qualify as long as they do not involve the primary use of fossil fuels as direct inputs to the storage cycle. Senate floor debate established that the definition also includes systems using geothermal resources to produce electricity (S17806, October 9, 1978).

The Conference Report states that water is to be included within the meaning of the term renewable resources "with respect to hydro-electric facilities at existing dams." Clause (i) of paragraph (a) implements this requirement by excluding water as a renewable resource if it is used at a facility which contains a dam or other structure for impounding water, construction of which was not complete as of the date of the application for qualification, or which requires additional construction or enlargement (other than repair or reconstruction) in order to become operative. Under these standards, a hydroelectric facility can not become a qualifying small power production facility unless the impoundment portion of the facility is complete as of the date of the filing for qualification.

The definition of "primary energy source" for small power production facilities as set forth in section 3(17)(B) of the Federal Power Act, indicates that qualifying small power production facilities may make limited use of fossil fuels for ignition, startup, testing, flame stabilization and control purposes, as well as for fuel substitution during outages of a normal fuel supply system.

For ignition, startup and testing purposes, the Commission proposes in subparagraph (2), that the amount of fossil fuel planned to be burned for such purposes not exceed 500 barrels of oil (or its Btu equivalent in gas) per megawatt of rated capacity per year. For flame stabilization and control purposes, the proposed maximum amount is the equivalent of 0.2 barrels of oil per megawatt-hour of generation except for facilities burning solid municipal waste, for which the limit is the equivalent of 0.5 barrels of oil per megawatt-hour of generation.

Most facility outages are likely to involve essential power generation equipment, including the fuel combustion unit, and substitution of a fossil fuel would not restore the facility to proper operation. Based on utility experience with outages which do not involve the generator, turbine or fuel combustion unit, we propose that the amount of fossil fuel used as a substitute during outages of the normal fuel supply system not exceed the Btu equivalent of 110 barrels of oil per megawatt of rated capacity per year.

The proposed total amount of fossil which may be utilized for all purposes thus would not exceed the equivalent of 610 barrels of oil per year per magawatt of rated capacity, plus the equivalent of 0.2 barrels of oil per hour (0.5 for solid municipal waste) per megawatt of rated capacity during operation of the facility.

Subparagraph (3) requires the applicant to submit an estimate of planned use of fossil fuel by the facility, supported by any design characteristics or specifications of the equipment used in the facility.

Paragraph (b) implements the statutory requirement that the rated power production capacity of a small power production facility not exceed 80 megawatts. In order to implement this limitation, we propose to limit the maximum size standard to facilities that use the same energy resource and are owned by the same person. The Commission believes that limiting the applicability of the 80 megawatt maximum size to facilities meeting these stricter standards will encourage the development of small power production facilities as intended by the Congress. For purposes of this section, we propose to define "facilities located at the same site", except for hydroelectric facilities, as facilities located within one mile of the facility for which certification is sought. For hydroelectric facilities, we set forth the additional requirement that, to be considered to be located at the same site, the hydroelectric facilities must use water from the same impoundment for power generation. We propose to add this additional limitation to hydroelectric facilities because use of the one mile rule alone might discourage the development of facilities on a portion of a river with high energy potential which could not be effectively developed with one larger unit.

Clause (iii) states that an applicant may seek to rebut the presumption that facilities located within one mile of the facility for which certification is sought, using the same energy resource and owned by the same person should be considered to be located at the same site. Determinations regarding the rebuttal of the presumption will be based upon the extent to which factors other than an attempt to circumvent the 80 megawatt capacity limitation required smaller physically separated facilities and the extent to which rebutting the presumption is consistent with conservation of energy and optimal development of resources.

We considered but rejected as administratively infeasible a rule by which facilities located beyond the one mile limit solely for the purpose of circumventing the 80 mw limit would be excluded from qualification. We invite comment on how to implement the Congressional purpose of limiting the benefits of qualifying status and yet not discourage the development of resources.

Subparagraph (2) sets forth provisions for the minimum size of qualifying small power production facilities. It is clear that the minimum fixed costs associated with a small power production facility will set some minimum size of a generating unit below which there is little possibility that the unit can be economic, and therefore resource-efficient. These minimum fixed costs will vary between alternative forms of small power production facilities, both as a consequence of technology advancements and because the cost of interconnecting each facility to a power system varies with respect to metering, switching, supervision, control and safety provisions.

Nevertheless, we have made an effort to identify a practical minimum size, in order to reduce consideration of possibilities which are unlikely to prove viable. A 10-kilowatt unit is proposed as the minimum size for qualification, unless there is a showing that waiver is necessary to encourage conservation of energy and optimization of use of resources.

We recognize that the Department of Energy is sponsoring the development of a number of wind power units of less than 10 kilowatts capacity. Testing and demonstration of these units will require interconnection with utility systems, and, in the event that qualifying status is needed, we may invoke the standard as set forth above for such test operations. However, there seems to be no advantage in encouraging uneconomic operation of commercial systems or burdening utilities with analysis and planning for hypothetical systems which are unlikely to be constructed because they cannot recover the investment costs. Hence, we propose a minimum size of 10-kilowatts with a provision for exemption. We request comment on the

feasibility and advisability of a 10-kilowatt minimum size limitation.

Paragraph (c) sets for efficiency standards for small power production facilities using limited access renewable resources.

Where use of a primary energy resource will not significantly limit its use by others, economics will generally dictate the optimum level of efficiency for a small power production facility. Therefore, no minimum standard of efficiency will be mandated for facilities deriving primary energy input from biomass and renewable resources such as solar energy or the wind, which at this time are characterized by essentially unlimited access.

For facilities deriving primary input from energy sources characterized by limited supply or access, such municipal waste, geothermal wells or existing dams, minimum efficiency standards may be desirable to assure reasonable energy recovery from a limited resource. (Access to the limited resource may confer a degree of monopoly power, so that economic forces may not necessarily assure efficient use of the resource.)

For such limited energy resources other than hydroelectric facilities, we propose that the facility achieve a minimum level of 40 percent of the ideal Carnot efficiency achievable with practical working fluid temperatures. Efficiency is defined as the ratio of the output of the heat engine as useful mechanical energy to the energy input to the facility.

Hydroelectric small power production facilities are a special case of a limited access energy resource. The existing licensing criteria include a determination of whether a proposed installation will have an acceptable level of efficiency. For non-jurisdictional hydroelectric projects, we propose that a minimum hydraulic efficiency of 60 percent be realized.

Paragraph (d) is designed to implement the requirement in the new sections 3(17)(C)(ii) and (18)(B)(ii) that a qualifying small power production facility or cogeneration facility be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogenerational facilities or small power production facilities). Regarding this provision, the Commission notes that the Conference Report states that:

> [e]lectric utilities may participate in an entity which owns such (qualifying small power production or cogeneration) facilities with other persons, and such entity could qualify under these definitions.
>
> The test of this case is whether the entity which owns the facility is primarily engaged in the generation or sale of electric power other than in connection with its ownership of the cogeneration facilities or small power production facilities.

Thus, either directly or through a subsidiary company, an electric utility could participate in the ownership of a qualifying cogeneration or small power production facility. We note that under a literal interpretation of the Conference Committee's statement, several electric utilities could form a subsidiary which owned small power production or cogeneration facilities. Such a subsidiary would constitute an entity which is not primarily engaged in the generation or sale of electric power other than in connection with its ownership of cogeneration or small power production facilities. Under such an interpretation, the subject facilities would be eligible to receive qualifying status. We believe, however, that the thrust of Section 201 of PURPA is to limit the advantages of qualifying status to cogeneration and small power production facilities which are not owned exclusively by electric utilities or their subsidiaries. Under the proposed regulations, based on the proportion of ownership by electric utilities, public utility holding companies, or subsidiaries of either, the Commission will determine whether more than 50 percent of the entity which owns the cogeneration or small power production facility is comprised of these electric interests. If it is, then the facilities may not be granted qualifying status.

§ 292.206 Qualifying requirements for cogeneration facilities.

Section 292.206 sets forth the requirements for qualifying cogeneration facilities. Paragraph (a) provides that the cogeneration facility must produce electric energy and other forms of useful energy (such as heat or steam) which are used for industrial, commercial heating or cooling purposes. These standards are set forth in subsection 3(18)(A) of the Federal Power Act, as amended by PURPA. This definition reflects the focus of PURPA on sales of electricity by industrial or commercial generating facilities. The key concept is that electricity production as a co-product of process heat or non-electric energy forms may be more resource-efficient than separate production of electricity and other energy forms and, when so, should not be inhibited by artificial barriers. Resource efficiency translates generally to economic efficiency. Hence, a major objective of the Commission's rules is to help assure that projects are economic, and specifically to assist potential cogenerators in their evaluations of project economic feasibility.

Paragraph (b) sets forth the same limitations on utility ownership as apply to small power production facilities (see pp. 16–18, *supra*).

Paragraph (c) sets forth definitions for terms used to provide efficiency standards for qualifying cogeneration facilities. The Commission's concern with the fuel efficiency of a qualifying cogeneration facility is that the benefits obtained by such a designation be matched by significant improvement in resource utilization. Addition of a heat recovery unit to a diesel engine exhaust, or of a steam turbine generator unit to a process heat waste gas stream might constitute cogeneration in the strict sense of the term, but would only represent a significant improvement in resource utilization if a substantial fraction of the energy potentially available from the thermal stream is actually recovered and used. Consequently, threshold values of efficiency and heat utilization are proposed as a primary basis for qualification of units using energy resources of limited availability, specifically natural gas and petroleum. Lower values may be justified by presentation of evidence that the specified levels are not practicably attainable and that significant resource conservation will be achieved.

For a cogeneration facility coupled to an industrial process which operates in a batch mode, the performance of the facility shall be determined in terms of average values over the duration of a batch run. For any other cogeneration process, the performance of the system shall be determined in terms of steady state operation at rated capacity.

Subparagraph (1) defines "heat engine" as a device which operates on a thermodynamic cycle and converts heat energy to mechanical energy. Subparagraph (2) defines "efficiency of a heat engine" as the ratio of the useful output of a heat engine as mechanical energy to the sum of the energy inputs to the heat engine. Subparagraph (3) defines the "useful energy output of a thermal process" as the difference between the heat inputs to the process and the heat carried away by the heating medium. Subparagraph (4) specifies that, in the use of energy in the form of fossil fuel, energy input is to be measured by the lower heating value of such fuel.

Finally, subparagraph (5) defines "overall energy efficiency" as the ratio of the sum of all useful energy outputs including the useful output of any thermal process to the energy input to the facility. Any energy used exclusively in the thermal process of a topping cycle, or exclusively in the heat engine of a bottoming cycle (supplementary filing) is not included as energy output or energy input for the purpose of determining the overall cogeneration system efficiency.

A qualifying cogeneration facility may be subject to fuel use regualtions

established under the Powerplant and Industrial Fuel Use Act (FUA). Under the Act, new powerplants or fuel burning installations of a single unit having a design fuel heat input of 100 million Btu's per hour or greater, or which result in two or more units at the same site having a combined design fuel heat input rate of 250 million Btu's per hour or greater, are prohibited from burning natural gas or petroleum, unless an exemption is provided by the Secretary of Energy. FUA specifically authorizes the Secretary to exempt cogeneration facilities from the prohibition if the benefits of cogeneration are otherwise unobtainable. The Economic Regulatory Administration has issued interim rules under which such exemptions might be granted.

Under PURPA, the Commission may establish fuel use requirements for qualifying cogenerators of any size, but any such requirements regarding the use of natural gas or petroleum would only be effective at fuel heat input levels below the thresholds established by FUA for action by the Secretary of Energy. At such lower levels, a fuel burning installation that does not seek classification as a qualified cogenerating facility would not be subject to an FERC rule and could burn natural gas or oil. Hence, a restriction on the use of gas or oil for cogeneration, imposed by the Commission, could discourage cogeneration at the lower heat input levels, while not significantly reducing the use of oil or natural gas. We conclude that restrictions or requirements on fuel use by qualifying cogeneration facilities are not appropriate in this proposed rule.

Paragraph (d) sets forth efficiency standards for cogeneration facilities using bottoming cycles which use any primary energy source except coal or coal-dervied fuels. Because of the abundance of this energy resource at this time, we propose not to impose any limit on the efficiency of such cogeneration facilities and rather to let the marketplace provide the motivation for optimizaiton of efficiency.

For bottoming cycle cogeneration facilities using energy resources other than coal or coal-derived fuels to obtain qualifying status, either the useful energy output of the heat engine must be no less than 15 percent of the difference between the energy input to the facility and the useful energy output of the thermal process, or the heat engine must attain a minimum of 40 percent of the ideal Carnot efficiency achievable with the maximum and minimum temperatures experienced by the working fluid. In either case, the overall cogeneration facility energy efficiency must be no less than 60 percent.

Efficiency standards for cogeneration facilities using topping cycles vary depending on the primary energy source. Paragraph (e) sets forth efficiency standards for topping-cycle cogeneration facilities using natural gas, petroleum, or any derivative thereof as a primary energy source. The prices of these energy sources are subject to government control, and therefore the prices do not reflect replacement costs. As a result the failure to limit the benefits of qualificaiton to efficient facilities might encourage overconsumption of these fuels. To prevent that result, we propose only to qualify gas or oil burning facilities if:

(1) the useful energy output of the heat engine is no less than 20 percent of the energy input to the facility;

(2) the useful energy output of the thermal process is no less than 45 percent of the heat energy discharged by the heat engine; and

(3) the overall facility energy efficiency is no less than 60 percent.

The next category of topping-cycle cogeneration facilities are those whose primary energy source is characterized by limited access. Use of these resources by one cogenerator deprives another, possibly more efficient cogeneration facility of the opportunity to use these particular energy sources. As a result, we propose to impose efficiency standards on facilities using these resources. The proposed

standards are lower than those imposed on facilities using oil or gas.

There is an additional need for efficiency standards for facilities of over 30 megawatts electrical capacity which use biomass or renewable resources, and for which a condition of limited access characterizes the primary energy source. For such facilities, efficiency standards are necessary to ensure that the facility represents a *bona fide* cogeneration system, and not merely an attempt to evade the 30 megawatt statutory limit on exemption from regulation for small power production facilities. The proposed standard is identical to that proposed for facilities of all sizes using primary energy sources characterized by limited access. We do not expect that this standard will exclude any serious cogeneration proposal from the benefits of qualifying status.

Accordingly, in paragraph (f), we propose that, for topping-cycle cogeneration facilities over 30 megawatts using biomass, renewable resources and waste other than municipal waste, or geothermal energy or any combination thereof, and for topping cycle facilities of any size using geothermal or municipal waste as their primary energy source, efficiency standards be set as follows:

(1) the useful energy output of the heat engine must be no less than 15 percent of the energy input to the facility;

(2) the energy output of the thermal process must be no less than 40 percent of the heat energy discharged by the heat engine; and

(3) the overall facility energy efficiency must be no less than 55 percent.

For cogeneration facilities using either topping or bottoming cycles, using coal or coal-derived fuel as the primary energy source. There are no statutory limits on efficiency for qualification. The abundance of this energy resource permits reliance on the market to optimize efficiency.

Paragraph (g) sets forth a proposed minimum size of 10 kilowatts (electric).

§ 292.207 Exemptions from qualifying requirements.

This section provides that the Commission may waive certain requirements for qualification of cogeneration or small power production facilities, if it determines that waiver is necessary to encourage conservation of energy and optimization of efficiency of use of resources. The Commission may not waive the qualifying requirements for small power production facilities concerning the primary energy source of the facility and limiting ownership to persons not primarily engaged in the generation or sale of electric power. We propose that the ownership limitations for cogeneration facilities similarly be excepted from the waiver provisions along with the statutory definition of a cogeneration facility set forth in § 292.206(a).

§ 292.208 Procedures for determination of qualifying status.

Section 292.208 sets forth the procedures to be used for the Commission to determine whether a facility is to be granted a qualifying status. Paragraph (a) provides that in uncontested proceedings the Commission shall issue an order granting, denying or tolling the time for issuance of an order within 90 days of the filing of the application. Unless the applicant requests that the presumptions set for in § 292.205(b)(1) be rebutted, if no order is issued within 90 days of the filing of the application, it shall be deemed to have been granted. If any party files a protest to an application, the time for the issuance of an order is extended to 120 days. In the case of contested applications, the provisions for automatic granting of qualifying status do not apply.

Under clause (2) if an applicant seeks to rebut the presumptions concerning facilities located at the same site for purposes of compliance with the 80 megawatt maximum limit on small power production facilitites, the application will be treated as a contested application. In that case, the

time for issuance of an order is extended to 120 days and qualifying status is not automatically granted if the Commission does not issue an order within that time period.

§ 292.209 Modification of qualifying facilities.

Paragraph (a) provides that the Commission may revoke the qualifying status of a facility if it ceases to comply with the qualifying requirements for small power production or cogeneration facilities. Paragraph (b) provides that, prior to undertaking any substantial alteration of a qualifying facility, a small power producer or cogenerator may apply to the Commission for a determination that the facility, as modified, will retain its qualifying status.

If a small power producer or cogenerator undertakes such changes without obtaining prior Commission approval, he must apply to the Commission to retain qualifying status. Under these procedures, the Commission is attempting to assure that facilities enjoying the benefits of qualifying status continue to comply with the standards for qualification, and also to enable a qualifying facility to undergo necessary changes with assurance that its qualifying status will no thereby be imperiled.

Written Comments

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should reference Docket No. RM79-54 on the outside of the envelope and on all documents submitted to the Commission. In order that the Commission be able to take into account as many comments as possible, the Commission requests that persons submitting comments assist in three ways. First, persons should identify specifically the section or subpart they are addressing. Second, comments should clearly state whether they involve technical, policy or legal matters. Finally, where comments urge a different approach from one presented, specific alternative language should be proposed to the extent practicable.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission by August 1, 1979, will be considered prior to the promulgation of final regulations.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, Pub. L. 95-621).

In consideration of the foregoing, it is proposed to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

(1) Subchapter K is amended in the table of contents by adding in the appropriate numerical order a new Part number and heading to read as follows:

SUBCHAPTER K—REGULATIONS UNDER THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

PART 292—QUALIFICATION OF SMALL POWER PRODUCTION AND COGENERATION FACILITIES UNDER SECTION 201 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

(2) Subchapter K is amended by adding a new Part 292 to read as follows:

PART 292—QUALIFICATION OF SMALL POWER PRODUCTION AND COGENERATION FACILITIES UNDER SECTION 201 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

Subpart A—[Reserved]

Subpart B—Certification of Qualifying Status

Sec.
292.201 Scope.
292.202 Applications for certification of qualifying status.
292.203 Notice.
292.204 Protests.
292.205 Qualifying requirements for small power production facilities.
292.206 Qualifying requirements for cogeneration facilities.
292.207 Exemptions from qualifying requirements.
292.208 Procedures for determination of qualifying status.
292.209 Modification of qualifying facilities.

(Authority: This part issued under the Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.* Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, Pub. L. 95-621.)

Subpart B—Certification of Qualifying Status

§ 292.201 Scope.

This subpart applies to the certification of small power production and cogeneration facilities as qualifying small power production and cogeneration facilities under sections 3(17)(C) and 3(18)(B) of the Federal Power Act, as amended by section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

§ 292.202 Applications for certification of qualifying status.

(a) *Filing requirements.* Any person seeking qualifying status for a small power production facility or cogeneration facility must file an application pursuant to the provisions of this section.

(b) *Pre-application requirements.* Before filing an application under this section, an applicant shall initiate or shall attempt to initiate discussions regarding the feasibility of interconnected operation with the entity with which the applicant proposes to so operate.

(c) *Contents of application.* Each application shall contain the following information:

(1) the name, address, and business of the applicant and, if the operator of the facility is a person other than the applicant, the name, address, and business of the operator;

(2) the electrical capacity of the facility;

(3) information regarding the efficiency of any heat engines, thermal process, other energy conversion processes, and the facility as a whole;

(4) the projected mode of operation of the facility, including anticipated daily and annual capacity factors of electric power generation and sale, a proposed plan for interconnected operation, and the proposed interconnection facilities to be provided by applicant and by the utility;

(5) a summary of the discussions between the applicant and the affected entity regarding the feasibility of interconnected operation between the applicant and affected entity conducted pursuant to § 292.202(b);

(6) a description of the equity ownership of the facility. If the owner of the facility, including any person which has ownership in any owner of the facility, is engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities, or small power facilities) the applicant shall state:

(i) the percentage of ownership by electric utilities, or by public utility holding companies, or by any person owned by either; and

(ii) the State and federal bodies which exercise ratemaking authority with respect to the applicant;

(7) a statement that the cogeneration or small power production facility complies or will comply with all applicable FERC rules and regulations.

(d) *Additional application requirements for small power production facilities.* In addition to the information required under § 292.202(c), applications for certification as

qualifying small power production facilities must contain the following additional information:

(1) a description of the facility;

(2) information sufficient to identify the primary energy source as biomass, waste or renewable resources and identifying any planned usage of fossil fuel; and

(3) the location of the facility in relation to other qualifying small power production facilities owned by the applicant and using the same energy resource.

(e) *Additional application requirements for cogeneration facilities.* In addition to the information required under § 292.202(c), applications for certification as qualifying cogeneration facilities must contain the following additional information:

(1) a basic description of the facility, including whether the facility uses a topping or bottoming cycle;

(2) a description of the energy inputs, including the primary energy source, any additional energy sources, and the energy content of any fuels used as energy sources; and

(3) a description of the energy outputs, indicating the type and size of heat engines, thermal processes, and other energy conversion processes.

§ 292.203 Notice.

(a) Applications filed under this section shall include a copy of a notice of the request for certification. The notice shall state the applicant's name, the date of the application, and a brief description of the facility for which qualification is sought and of the proposed interconnection. The notice shall be in the following form:

United States of America—Federal Energy Regulatory Commission

(Name of Applicant) ———————

Notice of Application for Certification of a (Small Power Production) (Cogeneration) Facility Pursuant to Section 3(17)(C) or 3(18)(B) of the Federal Power Act

On (date application was filed), (name and address of applicant) filed with the Federal Energy Regulatory Commission an application to be certified as a qualifying (small power production facility) (cogeneration facility) under Paragraph 3(17)(C) or 3(18)(B) of the Federal Power Act.

[Brief description of the facility].

Any person objecting to the granting of qualifying status may file a protest in accordance with the provisions of § 1.10 of the Commission's Rules and Regulations. All protests must be filed within 30 days after the date of issuance of this notice and must be served on the applicant.

(b) The applicant shall serve a copy of the notice on any entity with which the applicant proposes to interconnect, and a copy on any state regulatory authority with jurisdiction over the entity.

§ 292.204 Protests.

(a) Any entity served under § 292.203, or any other interested party, may file a protest pursuant to § 1.10 of the Commission's Regulations. Protests must be filed within 30 days of the issuance of public notice of the application. Protests must set forth specifically the grounds on which the protestant believes the facility for which the application is made should be denied certification of qualifying status. Any person filing such a protest shall serve a copy of the protest on the applicant.

(b) The applicant may file an answer to any protest. Such answer must be filed within 15 days of the service date of a protest. The applicant shall serve a copy of the answer on the party filing the protest.

§ 292.205 Qualifying requirements for small power production facilities.

To be certified as a qualifying small power production facility, a facility for which an application is filed must meet the following requirements:

(a) *Fuel use.*

(1) The primary energy source of the facility must be biomass, waste, renewable resources or any combination thereof. For purposes of this section, water is a renewable resource with respect to hydroelecric facilities except to the extent that such facilities:

(i) include dams or other structures for impounding water, the construction of which was not completed on or before the date of the filing of the application for qualification under § 292.202(a), or

(ii) require any construction or enlargement of impoundment structures (other than repair or reconstruction) in connection with their installation.

(2) Planned use of fossil fuel for start-up, testing, flame stabilization and control purposes and during outages of the fuel supply system may not exceed the following limits:

(i) for ignition, start-up and testing, not more then 500 barrels (bbl) of oil per year (or its Btu equivalent in gas) per megawatt of rated capacity;

(ii) for flame stabilization and control, not more than 0.2 bbl of oil per hour (or its Btu equivalent in gas) per megawatt of rated capacity during operation of the facility; except for facilities burning solid municipal waste, in which case the limit is the equivalent of 0.5 bbl of oil per megawatt hour of generation; and

(iii) during outages of the normal fuel supply system, not more than 110 bbl of oil (or its Btu equivalent in gas) per year per megawatt of rated capacity.

(3) An applicant shall submit an estimate of the planned use of fossil fuel by the facility and this estimate shall be supported, where available, by design characteristics or specifications of the equipment used in the facility.

(b) *Size of the facility.*

(1) *Maximum size.* (i) The rated power production capacity of the facility for which certification is sought, together with the capacity of any other facilities that use the same energy resource and are owned by the same person and are located at the same site, must be no greater than 80 megawatts.

(ii) For purposes of this paragraph, facilities are presumed to be located at the same site as the facility for which certification is sought if they are located within one mile of the facility for which certification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.

(iii) An applicant may seek to rebut the presumption in subparagraph (ii) for any facility located within one mile of the facility for which certification is sought. In determining whether the presumption has been rebutted, the Commission will consider:

(A) the extent to which factors other than the 80 megawatt capacity limitation dictate smaller, physically separated facilities rather than larger, integrated or physically contiguous facilities; and

(B) the extent to which consideration of the facility as being at a different site from other facilities is consistent with conservation of energy and optimally efficient use of resources.

(2) *Minimum size.* A facility must have a design capacity of at least 10 kilowatts. This provision may be waived if the Commission finds that granting qualifying status to the facility is necessary to encourage conservation of energy or the optimization of the efficiency of use of resources.

(c) *Efficiency standards for facilities using limited access renewable resources.*

(1) A facility using geothermal resources or municipal waste as a primary energy source must achieve a minimum of 40 percent of the ideal Carnot efficiency achievable with the maximum and minimum temperatures experienced by the working fluid.

(2) Hydroelectric facilities not regulated under Part I of the Federal Power Act must achieve hydraulic efficiency of at least 60 percent.

(d) *Ownership.* A small power production facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). For purposes of this paragraph, a small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power if more than 50 per cent of the equity interest in the facility is held by an electric utility or utilities, or

by a public utility holding company, or companies, or any combination thereof. If a subsidiary of an electric utility or public utility holding company has an ownership interest in a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or public utility holding company.

§ 292.206 Qualifying Requirements for Cogeneration Facilities.

(a) The cogeneration facility must produce electric energy and other forms of useful energy (such as heat or steam) which are used for industrial, commercial, heating or cooling purposes.

(b) A cogeneration facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). For purposes of this paragraph, a cogeneration facility may not be certified as qualifying if more than 50 per cent of the facility is owned by an electric utility or utilities or a public utility holding company, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or public utility holding company has an ownership interest in a facility, the subsidiary's ownership interest shall be counted as ownership by an electric utility.

(c) For purposes of this subsection,

(1) "heat engine" means a device which operates on a thermodynamic cycle and converts heat energy to mechanical energy;

(2) "efficiency of a heat engine" means the ratio of the useful output of a heat engine as mechanical energy to the energy inputs to the heat engine;

(3) "useful energy output of a thermal process" means the difference between the heat input to the process and the heat carried away by the heating medium;

(4) "energy input", in the case of energy in the form of fossil fuel, is to be measured by the lower heating value of such fuel;

(5) "overall energy efficiency" means the ratio of the sum of all useful energy outputs including the useful output of any thermal process to the energy input of the facility. Any energy used exclusively in the thermal process of a topping cycle, or exclusively in the heat engine of a bottoming cycle (supplementary filing) shall not be included as energy output or energy input for the purpose of determining the overall cogeneration system efficiency.

(d) For bottoming cycle cogeneration facilities using any primary energy source, except coal or coal-derived fuels, the following efficiency standards apply:

(1)(i) the efficiency of the heat engine must be no less than 15 percent with regard to the difference between the energy input to the facility and the useful energy output of the thermal process; or

(ii) the heat engine must attain a minimum of 40 percent of the ideal Carnot efficiency achievable with the maximum and minimum temperatures experienced by the working fluid; and

(2) the overall cogeneration facility energy efficiency must be no less than 60 percent.

(e) For topping-cycle cogeneration facilities using natural gas, petroleum, or any derivative thereof, as a primary energy source, the following efficiency standards apply:

(1) the efficiency of the heat engine must be no less than 20 per cent with regard to the energy input to the facility;

(2) the energy output of the thermal process must be no less than 45 per cent of the difference between the energy output of the heat engine and the useful energy output of the heat engine; and

(3) The overall facility energy efficiency must be no less than 60 per cent.

(f) for topping-cycle cogeneration facilities over 30 megawatts using biomass, renewable resources other than municipal waste, or any combination thereof, and for any

facilities using geothermal energy or municipal waste as their primary energy source, the following efficiency standards apply:

(1) the useful energy output of the heat engine must be no less than 15 percent of the energy input to the facility;

(2) the energy output of the thermal process must be no less than 40 percent of the energy output of the heat engine minus all useful energy output of the heat engine; and

(3) The overall facility energy efficiency must be no less than 55 per cent.

(g) *Minimum size.* The cogeneration facility must have a design capacity of at least 10 kilowatts (electric).

§ 292.207 Exemptions from Qualifying Requirements.

The Commission may waiver any of the provisions of §§ 292.205 and 292.206 except for §§ 292.205(a)(1); 292.205(d); 292.206(a); and 292.206(b), if it determines that the waive is necessary to encourage conservation of energy and optimization of efficiency of use of resources.

§ 292.208 Procedures for determination of qualifying status.

(a) *Uncontested applications.* Except as set forth in subparagraph (2), the following procedures apply to uncontested applications for certification of qualifying status:

(1) If no protest is received during the period allowed, the Commission shall issue an order within 90 days of the filing of a complete application, granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify the specific requirements which were not met. If no order is issued within 90 days of the filing of the application, it shall be deemed to have been granted.

(2) An application for certification as a small power production facility seeking to rebut the presumption set forth in § 292.205(b)(1)(ii) of this subpart will be considered a contested application under paragraph (b) of this section.

(b) *Contested applications.* If any person files a protest to an application for certification, tl.e Commission shall issue an order within 120 days of the filing of the original application.

§ 292.209 Modification of qualifying facilities.

(a) The Commission may revoke the qualifying status of a qualifying cogeneration or small power production facility if sucy facility undergoes changes which cause the facility not to be in compliance with the provisions of § 292.205 or § 292.206.

(b) Prior to undertaking any substantial alteration or modification of qualifying facilities, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

(c) If a small power producer or cogenerator undertakes any substantial alteration or modification of qualifying facilities without a determination of the Commission that such alteration or modification will not result in a revocation of qualifying status, the small power producer or cogenerator shall apply for certification pursuant to § 292.202(a) of the facilities as altered or modified.

(d) For purposes of this section, the term "substantial alteration or modification of qualifying facilities" means such alteration, modification or other changes as would materially affect the accuracy of the information submitted pursuant to § 292.202(a).

¶ 32,029 Certain Transportation Sales and Assignments by Pipeline Companies Not Subject to FERC Jurisdiction

44 F. R. 40072 (July 9, 1979).

[18 CFR Part 157]

[Docket No. RM79-24]

Certain Transportation, Sales and Assignments by Pipeline Companies Not Subject to Commission Jurisdiction Under Section 1(c) of the Natural Gas Act

July 2, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission presents its tentative views of the status of natural gas pipelines which are exempt from the Commission's jurisdiction under section 1(c) of the Natural Gas Act (Hinshaw pipelines), in light of the definitions of the Natural Gas Policy Act of 1978 (NGPA). To the extent that Hinshaw pipelines are to be treated as local distribution companies under the NGPA, the proposed rule would create a procedure for the issuance of blanket certificates of public convenience and necessity to allow Hinshaw pipelines to sell, assign and transport gas to the same extent that intrastate pipeline are so authorized under the NGPA.

DATES: Written comments by July 30, 1979. Requests to participate at public hearing due by July 23, 1979. Public hearing on July 30, 1979.

ADDRESS: All comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (Reference Docket No. RM79-24).

FOR FURTHER INFORMATION CONTACT: Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426, (202) 275-0427.

SUPPLEMENTARY INFORMATION:

A. Background

The Federal Energy Regulatory Commission (Commission) is proposing a rule which would permit pipeline companies with facilities excluded from Commission jurisdiction pursuant to section 1(c) of the Natural Gas Act (NGA) to apply for certain blanket certificate authority pursuant to section 7(c) of the NGA. Any such certificate issued pursuant to section 7(c) of the NGA would permit the transportation and sale of natural gas in interstate commerce and the assignment of contractual rights to natural gas under the same conditions as those activities are permitted to be engaged in by intrastate pipelines under sections 311 and 312 of the Natural Gas Policy Act of 1978 (NGPA).

Comments are solicited on this proposed rule and on the proposed interpretations of the definitions set forth in the following discussion.

B. Discussion

An important objective of the NGPA is to remove artificial restraints on the flow of gas between the interstate and the intrastate market. As part of its effort to reach this objective, Congress adopted sections 311 and 312 of the NGPA. Those sections permit the Commission to authorize intrastate pipelines to transport, sell, or assign natural gas to the interstate market. However, since only intrastate pipelines may transport natural gas under section 311(a)(2), sell natural gas under section 311(b) or assign natural gas under section 312(a), the effectiveness of those provisions, as well as the effectiveness of the policies which they implement, are dependent to a significant degree on the definition of an intrastate pipeline.

Section 2(16) of the NGPA defines "intrastate pipeline" as follows:

(16) INTRASTATE PIPELINE.—The term "intrastate pipeline" means any person

engaged in natural gas transportation (not including gathering) which is not subject to the jurisdiction of the Commission under the Natural Gas Act (other than any such pipeline which is not subject to the jurisdiction of the Commission solely by reason of section 1(c) of the Natural Gas Act).

The problem which this rule addresses arises out of uncertainty as to the status of those portions of a pipeline company's facilities which are not subject to Commission jurisdiction by reason of section 1(c) of the Natural Gas Act (referred to in this order as "Hinshaw facilities"). The Commission's tentative views on the proper characterization of such facilities are set forth below and comments thereon are solicited. The proposed rule is necessary to insure that Hinshaw pipelines may proceed to make transactions under NGPA sections 311 and 312 without regard to the final resolution of these questions.

Pipeline companies completely exempted by section 1(c) are defined to be "local distribution companies." The problem of categorization arises when the pipeline company holds an exemption from Commission jurisdiction pursuant to section 1(c) of the NGA as to another portion of its facilities. The Commission believes that the NGPA requires that Hinshaw pipelines be classified as local distribution companies. The Statement of Managers explains that such pipelines are so classified in order to insure that they will be subject to incremental pricing.[1]

The effectiveness of NGPA sections 311 and 312, dealing with certain transportation and sales of natural gas and assignments by interstate pipelines, is diminished by the determination that a pipeline holding an NGA section 1(c) exemption is to be treated as a local distribution company (as defined in section 2(17) of the NGPA), since transportation services, sales and assignments may be made under NGPA sections 311(a) (2), 311(b) and 312 only by intrastate pipelines. However, classifying a Hinshaw pipeline as a local distribution company would preserve that company's ability to buy natural gas under section 311(b) or receive assigned gas under section 312. This option would not appear to be available if the Hinshaw pipeline were classified as an intrastate pipeline. The Commission invites comment upon how the policy objectives of both Titles II and III of the NGPA can be furthered by interpretation of section 2(16).

The Commission is currently of the view that companies that are exempted by section 1(c) of the NGA are "local distribution companies." Any change in this view resulting from comments receivedd in this rulemaking will be applied only prospectively.

While the Commission is not prepared at this time to express a final opinion as to the extent that pipelines which have Hinshaw facilities may nevertheless be treated as "intrastate pipeline" under the NGPA, the proposed rule nonetheless would permit transactions of the kind authorized under sections 311 and 312 of the NGPA to proceed. The proposed rule establishes a blanket certificate procedure permitting Hinshaw pipelines to carry out transactions of the kind permitted by NGPA sections 311 and 312. The effect of the proposed rule would be to permit Hinshaw pipelines to provide transportation sevice, make sales, and assign contractual rights to natural gas quickly and without confusion as to the extent of any possible authority under NGPA sections 311 and 312.

An example should clarify the rule. A pipeline company operates in a producing state but also receives natural gas from an interstate pipeline under a section 1(c) exemption. In order to permit the company to engage in sales and transportation of the kind authorized by NGPA sections 311 and 312, the proposed rule would allow the company to apply for a one-time blanket authorization pursuant to NGA section 7(c) permitting, in effect, transportation,

[1] H.R. Report No. 95-1752, 95th Cong. 2nd Sess. (1978) at 70, 96.

sales and assignments of natural gas in interstate commerce identical to that permitted by NGPA sections, 311 and 312 for intrastate pipelines. In this way, the company as a whole would be able freely to transport and sell natural gas and to assign contractual rights to natural gas. This would be true despite the existence of an NGA section 1(c) exemption with respect to certain of its facilities, even if the scope of that exemption was uncertain.

The blanket certificate would not impair the continued validity of the pipeline company's NGA section 1(c) exclusion from Commission jurisdiction as to the its other transactions. The NGA section 7(c) certification contemplated by the proposed rule would be strictly limited to the type of activity permitted for intrastate pipelines by NGPA sections 311 and 312. In addition, in any future proceedings, the Commission would not assert its jurisdiction over other intrastate transactions which are not covered by the blanket certificate.[2] Nor would acceptance of the limited certificate affect the scope of the NGA section 1(c) exemption if a question as to scope were raised in any future proceeding.

The terms and conditions which would be contained in these certificates would be only those necessary to meet the statutory requirements of NGPA sections 311 nd 312 and NGA section 7(c). These terms and conditions, relating to Part 284 of the Commission's Regulations, would not embody the regulations which generally apply to natural gas companies subject to the Commission's jurisdiction under the NGA. The Commission does not contemplate the need to include such NGA requirements in the blanket certificates.

Certificate conditions will require that all volumes sold pursuant to the blanket certificate (1) shall be subject to incremental pricing to the same extent as if the sale had been authorized by section 311(b) of the NGPA[3] and (2) shall not exceed the volumes obtained intrastate sources.

The incremental pricing requirement in proposed paragraph (e)(2) is necessary to conform to the intent of Title II of the NGPA. The NGPA requires that certain volumes sold under Title III shall be incrementally priced by the buyer. (Section 203(a)(10)). If the blanket certificate did not contain such a condition, then the legislative intent to incrementally price natural gas flowing in interstate commerce may not be achieved. The volumetric requirement in proposed paragraph (e)(3) is to prevent interstate system supplies from being resold by the Hinshaw pipeline under terms appropriate for only intrastate market sources.

In this regard, a suitably conditioned certificate would be issued authorizing NGPA sections 311 and 312 type activities which not otherwise affect a pipeline company's already exempt status. Similarly, compliance with the Commission's Uniform System of Accounts and general reporting requirements, other than those required by NGPA sections 311 and 312 and the Regulations thereunder would be waived.

Pipeline companies making application for the type of NGA section 7(c) certificate discussed here should state that the rates to be charged would be those permitted by NGPA sections 311 and 312. In this regard, weighted average acquisition costs with respect to any sale under NGPA section 311 should not separate the cost of intrastate gas from interstate gas acquired pursuant to an exemption under NGA section 1(c).

Proposed paragraph (f) clarifies the status of pipelines with Hinshaw facilities that do not obtain a blanket certificate. Such pipelines are not authorized to participate in transactions authorized by section 311 or 312 of the NGPA. Pipeline companies holding

[2] The Commission has in the past granted limited NGA section 7(c) certificate authority. See, for example, *United Gas Pipe Line Company* and *Delhi Gas Pipeline Corporation*, Docket Nos. CP77-525 and CP77-529, orders issued December 15, 1977, and January 26, 1978.

[3] See section 203(a)(10) of the NGPA.

exemptions under NGA section 1(c) may, of course, still sell gas in fuel oil displacement transactions under subpart F of Part 284 as local distribution companies.

Two other alternatives are available to pipeline companies with Hinshaw facilities. First, a separate corporation can be created to operate the Hinshaw facilities. Such a reorganization would leave the company not operating the Hinshaw facilities as qualifying as an "intrastate pipeline" under section 2(16) of the NGPA. Second, the pipeline company can stop taking gas from the interstate market and request any interstate pipeline suppliers to file for abandonment.

The Commission proposes this rule because it is in the public interest to assist in the creation of a national market for natural gas as well as a national transportation system as intended by Congress in the NGPA. For this reason, the Commission believes that pipeline companies with Hinshaw facilities should not be discouraged from making available excess gas supplies and using transportation facilities as contemplated by sections 311 and 312 of the NGPA and the Regulations thereunder.

Written Comment Procedures

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to 4:30 p.m., E.S.T., July 30, 1979, will be considered by the Commission prior to the promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NE., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM79–24.

D. Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on July 30, 1979, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., E.S.T., on July 23, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM79–24 as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m. on July 27, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, as the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement.

Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the

Commission's Office of Public Information.

(Natural Gas Act, 15 U.S.C. 717, *et seq.* Natural Gas Policy Act of 1978, Pub. L. 95-621. Department of Energy Organization Act, Pub. L. 95-91; Administrative Procedure Act, 5 U.S.C. 500, *et seq.*, E.O. 12009, 42 F.R. 46267).

In consideration of the foregoing, the Commission proposes to add a new § 157.21 to Part 157, Subchapter E, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the direction of the Commission.

Lois D. Cashell,

Acting Secretary.

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT.

1. Part 157, Subchapter E, Chapter I of Title 18, Code of Federal Regulations, is amended by adding in the appropriate numerical order a new section to read as follows:

§ 157.21 Certain transportation, sales and assignments by pipeline companies not subject to Commission jurisdiction under section 1(c) of the Natural Gas Act.

(a) *Applicability.* This section applies to persons who are not subject to the jurisdiction of the Commission by reason of section 1(c) of the Natural Gas Act.

(b) *Blanket certification.* Upon application therefor, the Commission will issue to a pipeline company to which this section is applicable, a blanket certificate, pursuant to section 7(c) of the Natural Gas Act, authorizing such pipeline company to engage in the sale, transportation, or assignment of natural gas to the same extent and in the same manner that intrastate pipelines are authorized to engage in such activities by sections 311 and 312 of the Natural Gas Policy Act of 1978 (NGPA) and Subparts B, C, and D of Part 284 of this chapter.

(c) *Effect of certificate.* (1) A certificate issued pursuant to this section will authorize the pipeline company to engage in transactions of the type authorized by Part 284.

(2) Acceptance of a certificate or conduct of an activity authorized thereunder will:

(i) Not impair the continued validity of any exclusion under section 1(c) of the Natural Gas Act which may be applicable to such pipeline company, and

(ii) Not subject such pipeline company to the Natural Gas Act jurisdiction of the commission except to the extent necessary to enforce the terms and conditions of the certificate.

(d) *Application procedure.* Applications for blanket certificates shall state:

(1) The name of the applicant,

(2) The volumes of natural gas received during a 12 month period by the applicant from another person within or at the boundary of a State which are exempt from the Natural Gas Act jurisdiction of the commission by reason of Section 1(c) of the Natural Gas Act,

(3) The total of natural gas received by the applicant from all sources during the same time period,

(4) Citation to all currently valid declarations of exemption issued by the Commission under Section 1(c) of the Natural Gas Act, and

(5) A statement that the applicant will comply with the conditions in paragraph (e) of this section.

(e) *General conditions.* (1) Any transaction authorized under a blanket certificate shall be subject to the same terms and conditions that would apply if the transaction were authorized by section 311 and 312 of the NGPA.

(2) Prior to engaging in any sale or assignment under the blanket certificate to a buyer; subject to the incremental pricing provisions of Title II of the NGPA, the selling pipeline shall receive an undertaking from the buyer to incrementally price the volumes sold to the same extent required for

transactions authorized under section 311(b) or 312 of the NGPA.

(3) The volumes of natural gas sold or assigned under the blanket certificate may not exceed the volumes obtained from intrastate sources.

(f) *Pipeline companies without blanket certificate.* A pipeline company to which this section applies and which does not obtain a blanket certificate under this section is not authorized to participate in intrastate pipeline transactions otherwise authorized by Subparts B,C, D and F of Part 284 of this chapter.

¶ 32,030 Research, Development and Demonstration Expenses Related To Rate Schedules Filed by Electric Utilities

44 F. R. 40525 (July 11, 1979).

[18 CFR Part 35]

[Docket No., RM 79-58]

Research, Development, and Demonstration Expenses Relating to Rate Schedules Filed by Electric Utilities

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is proposing to amend its Regulations under the Federal Power Act (18 CFR Part 35) by adding a new §35.26. The new section provides that certain research, development, and demonstration contributions may not be charged to the utilities' wholesale electric customers as part of initial rate schedules filed under § 35.12 or as part of changes in rate schedules filed under § 35.13.

COMMENT DATE: August 8, 1979.

ADDRESSES: All filings should reference Docket No. RM79-58 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:
Luis S. Konski, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. (202) 275-4227.
Bonnie Cord, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capital Street, N.E., Washington, D.C. 20426, (202) 275-4285.

SUPPLEMENTARY INFORMATION:
Issued July 5, 1979.

The Federal Energy Regulatory Commission (Commission) is proposing to add a new section to its regulations relating to wholesale electric rate schedules filed with the Commission pursuant to section 205 of the Federal Power Act (18 CFR Part 35). The new section would provide that contributions paid by electric utilities to research development, and demonstration organizations or activities may not be included in wholesale cost of service filings for ratemaking purposes if: (1) The contributions are made by the utility on a voluntary basis; (2) the contributions are made on the basis of the contributor's retail sales; and (3) wholesale customers may make contributions on the basis of their own retail sales to these research, development, and demonstration efforts.

A. Background

Section 35.13 sets forth the filing requirements for changes in rate schedules required to be on file with the Commission under section 205 of the Federal Power Act (Act). Similarly, § 35.12 sets forth the filing requirements for initial rate schedules required to be on file with the Commission also under section 205 of the Act. Included in the information to be submitted under § 35.13 are the utility's costs in providing service to its customers. This information may also be submitted under § 35.12. These costs, if proper, may be reflected in the utility's charges for services and thus may be recovered from the utility's customers. One of the items that may be included in the cost of providing service under both § 35.13 and § 35.12 is contributions made by the utility to research, development, and demonstration (RD&D) efforts reasonably relating to the existing or future business of the utility.

The Commission, in the context of a rate proceeding, has determined that RD&D contributions by an electric utility to the Liquid Metal Fast Breeder Reactor (LMFBR) program should not be charged to the utility's wholesale customers. *Carolina Power & Light Company*, Docket No. ER76-495 (Phase II), Initial

Decision issued September 7, 1977, *affirmed in relevant part*, Opinion No. 19 issued August 2, 1978. The LMFBR program is an RD&D activity to which: (1) the utility contributes voluntarily; (2) the contributions are made on the basis of the contributor's retail sales; and (3) the wholesale customers could contribute independently based upon their own retail sales.

The Commission's decision in the *Carolina* proceeding was based upon a desire to avoid imposing involuntary contributions on the wholesale customers where the customers could made independent contributions and to avoid discouraging the customers' independent contributions by virtue of subjecting them to a double contribution. The purpose of the proposed rulemaking is to apply the *Carolina* principle to other RD&D programs which are similar to the LMFBR program in all material respects; that is, the contributions are voluntary, are based upon the contributor's retail sales, and may be made by wholesale customers independently. The Commission has no basis to believe that such similar RD&D programs should be distinguished from LMFBR in this respect.

Moreover, in addition to the rationale stated in the *Carolina* proceeding, the Commission believes that there are three additional reasons to prevent a utility from charging such RD&D contributions to its wholesale customers. First, substitution of the contribution in the utility's name for a contribution in the customer's name deprives the customer of participation in the decision as to how the contribution will be spent. Second, to the extent that the RD&D programs are worthwhile and contributions to them should be encouraged, substitution of a contribution based upon the utility's retail sales for a contribution based upon the customer's retail sales results in a reduction of the ultimate contribution to the RD&D program. Third, the Commission believes it to be an undue burden on its proceedings to inquire in every case as to which wholesale customers have contributed independently to particular RD&D programs, especially since past contributions, or lack of contributions, may not indicate whether such contributions will be made in the future.

Accordingly, the proposed regulation prevents a utility from including in its cost of service filing, and thus charging to its customers, any contribution to a research, development, and demonstration organization or activity which is voluntary, is based upon retail sales, and can be made independently by the utility's customers.

B. Summary of The Proposed Regulation

Paragraph (a) of proposed § 35.26 sets forth the general rule governing RD&D expenses as they relate to cost of service items under Part 35. Subparagraph (1) provides that an electric utility filing under § 35.13 or § 35.12 may not include in its cost of service filings, as a cost of service item, contributions to research, development, and demonstration activities or organizations: (1) which are made voluntarily by the electric utility; (2) which are made by the utility on the basis of its retail sales; and (3) to which the wholesaler customer may voluntarily contribute on the basis of its own retail sales. Subparagraph (2) of paragraph (a) provides that any party to a proceeding before the Commission involving a filing under Part 35 shall not include in its calculations of RD&D expenses, relating to cost of service, any contributions specified in subparagraph (1) (i) through (iii).

Paragraph (b) contains the definitions of RD&D expenses, organizations and activities. It should be noted that the proposed regulation uses the term "research, development, and demonstration," rather than "research and development" as used in the case cited above, in order to be consistent with the contemporary industry usage, § 35.22 of this part, and Part 101 of this subchapter (Commission's Uniform System of Accounts).

Subparagraph (1) of paragraph (b) defines "RD&D expenses" in accordance

with the definition of research, development, and demonstration expenditures set out in the Commission's Uniform System of Accounts (18 CFR Part 101 (Definition 27B)). In Definition 27B, RD&D expenditures are broadly defined as expenses incurred by public utilities, directly or indirectly, in pursuing research, development, and demonstration activities including, but not limited to, experiment, design, installation, construction or operation. Subparagraph (2) defines an "RD&D organization" as a research institute, industry association, foundation, university, engineering company or contractor that pursues research, development, and demonstration activities. Subparagraph (3) describes "RD&D activities" as research, development, and demonstration activities relating to the existing or future electric utility business or the environment in which the business operates.

C. Public Comment Procedures

Interested persons may participate in this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before August 8, 1979.

Each person submitting a comment should include his or her name and address, identify the notice (Docket No. RM79-58) and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

(Federal Power Act, *as amended*, 16 U.S.C. 791 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; E.O. 12009, 42 Fed. Reg. 46267.)

In consideration of the foregoing, the Commission proposes to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 35—FILING OF RATE SCHEDULES

1. Part 35, Subchapter B, Chapter I, of Title 18, Code of Federal Regulations, is amended in the table of contents by adding in the appropriate numerical order a new section number and heading to read as follows:

* * * * *

35.26 Research, development and demonstration expenses.

* * * * *

2. Part 35, Subchapter B, Chapter I, of Title 18, Code of Federal Regulations is amended by adding a new § 35.26 to read as follows:

§ 35.26 Research, development and demonstration expenses.

(a) *General Rule.* Research, demonstration, and development expenses relating to cost of service shall be treated in accordance the following rules.

(1) *Electric utilities.* An electric utility which files for a change in rate schedule under § 35.13 of this part, or which files an initial rate schedule under § 35.12 of this part, shall not include in its filing as a cost of service, any RD&D expenses representing contributions to an RD&D organization or activity if:

(i) The contributions are voluntarily made by the utility to the RD&D organization or activity;

(ii) The contributions are made by the utility on the basis of its retail sales; and

(iii) Independent contributions may be made by the utility's wholesale electric customer or customers to the RD&D

organization or activity on the basis of the customer's or customers' own electric retail sales.

(2) *Other parties.* Any party to any proceeding before the Commission involving a filing under Part 35 shall not include in its calculations of RD&D expenses relating to cost of service, contributions specified in paragraphs (a)(1)(i) through (iii) of this section.

(b) *Definitions.* For purposes of this section the following definitions apply.

(1) "RD&D expenses" means "research, development, and demonstration expenditures" as defined in the Commission's Uniform System of Accounts, Definition 27B (18 CFR Part 101).

(2) An "RD&D organization" means a research, development, and demonstration organization (including a research institute, industry association, foundation, university, engineering company or similar contractor), the purpose of which is to pursue RD&D activities.

(3) An "RD&D activity" means a research, development, and demonstration activity (including experiment, design, installation, construction or operation), reasonably relating to the existing or future electric public utility business or the environment in which the business operates.

¶ 32,031 Commission Determinations and Commission Review of Jurisdictional Agency Determinations

44 F. R. 48262 (August 17, 1979).

[18 CFR Part 275]

[Docket No. RM79-66]

Commission Determinations and Commission Review of Jurisdictional Agency Determinations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission is proposing two changes in its regulations concerning Commission review of jurisdictional agency determinations. The proposed regulations would (1) establish a procedure under which a jurisdictional agency would be able to withdraw a notice of determination, and (2) require that when the Commission determines that a notice of determination is incomplete, it must notify the parties to the proceeding before the jurisdictional agency and any purchaser.

DATES: Comments are due on or before September 15, 1979.

ADDRESS: Comments referencing Docket No. RM79-66 should be filed with: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100-H, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-0422.

August 13, 1979.

Background

On June 5, 1979, the Commission issued Part 275 of its regulations implementing the Natural Gas Policy Act of 1978 (NGPA) in final form.[1] Part 275 establishes the procedure by which the Commission will review jurisdictional agency determinations of the appropriate NGPA price category applicable to a particular natural gas well.

Section 275.202 provides that a notice of determination shall become final 45 days after the date on which the Commission receives the notice from the jurisdictional agency unless the Commission reverses or remands the determination or notifies the agency that the notice is incomplete during that period.

This procedure does not currently provide for a situation in which the jurisdictional agency seeks to withdraw a notice. The Commission has received four such requests to date. In one case the agency mistakenly submitted a notice of determination on an application which had not been finally resolved. In another case the agency requested withdrawal after it became aware that its determination had been based on an erroneous interpretation of our regulations. It is anticipated that such situations will continue to arise as jurisdictional agencies issue hundreds of determinations, and that the regulations proposed herein will be needed to accommodate this problem.

Nature of Proposed Regulations

Pursuant to the authority granted to the Commission in section 501(a) of the NGPA, we are proposing to provide a mechanism by which a jurisdictional agency may withdraw a notice of determination so long as the Commission receives actual notice of such withdrawal within 40 days after the date on which the notice was filed. Withdrawal shall render the notice of

[1] 44 FR 34475 (June 15, 1979)

determination a nullity. Within 5 days after being notified of a withdrawal the Commission must notify the parties to the proceeding before the jurisdictional agency and the purchaser. This provision will insure that a seller receives timely notice that the notice of determination issued on his well has been withdrawn and that the 45-day review period no longer applies to this determination.

During the period following promulgation of the interim regulations, the Commission has adopted an informal practice of informing the affected seller and purchaser whenever a notice of determination has been found to be incomplete. At this time we believe it is appropriate to reflect this informal procedure in our regulations. Accordingly, we are proposing an amendment to § 275.202(b)(2) which will require that when the Commission determines that a notice of determination is incomplete, it shall notify not only the jurisdictional agency (as the current regulation requires) but also the parties to the proceeding before the jurisdictional agency and the purchaser, within 45 days after the date on which the notice is received.

Under the regulations we propose today, both seller and purchaser will receive timely notice that the 45-day review period, which began on the date the Commission received the notice of determination, has either been tolled (in the case of an incomplete notice) or nullified (in the case of a withdrawal).

Effect of Withdrawal on Interim Collections

Pursuant to § 273.202 of the Commission's regulations, a seller may begin interim collections of the price for which he has applied when he has satisfied the filing requirements of § 273.202(d). Interim collections pursuant to this section terminate on the earlier of (1) the date on which the Commission receives a notice of the determination, or (2) 12 months after the first delivery for which interim collection is made.

Accordingly, once the Commission has received a notice of determination from the jurisdictional agency, interim collection authority under § 273.202 terminates and any further collection authority depends on the nature of the jurisdictional agency determination. If the determination is negative, the seller may collect only the otherwise applicable maximum lawful price. If the determination is affirmative, the seller may continue to make interim collections of the determined price under § 273.203. Any such interim collections under § 273.203 shall cease, however, if a jurisdictional agency withdraws a notice of determination under the withdrawal rule proposed today. The effect of a withdrawal under this rule shall be as follows:

(1) *Affirmative Determinations:* When a jurisdictional agency withdraws for its own reconsideration a notice of an affirmative determination, such determination is rendered a nullity as of the date the Commission notifies the parties to the proceeding before the jurisdictional agency and the purchaser, and is treated by the Commission as if it had never occurred. Accordingly, upon withdrawal of an affirmative determination, the seller of natural gas from the well in question is subject to the above-described interim collection provisions of § 273.202 (collection pending jurisdictional agency determination of eligibility). The Commission emphasizes that withdrawal of an initial jurisdictional agency notice by that agency does not terminate the interim collection authority under § 273.202. Accordingly, a seller who is awaiting jurisdictional agency reconsideration of a withdrawn affirmative determination may make interim collections under § 273.202.

(2) *Negative Determinations.* The provisions for affirmative determinations described in (1) above also apply to negative determinations. Accordingly, a seller who is awaiting jurisdictional agency reconsideration of a withdrawn negative determination

may make interim collections under § 273.202. In addition, it should be noted that if the jurisdictional agency subsequently makes an affirmative determination on the withdrawn application, and such determination is given final approval by the Commission, § 273.204 will apply. That section provides that the price finally determined to be the maximum lawful price may be collected retroactively for any period after the date of application during which the seller had collected a price less than the finally determined price.

To summarize what we have explained in detail above, a seller's statutory right to make interim collections remains intact when a jurisdictional agency withdraws a notice of determinations.[1]

Jurisdictional Agency Procedures Regarding Withdrawn Determinations

With respect to the rights of the seller or other parties during a jurisdictional agency's reconsideration of a withdrawn application, the Commission notes that section 503(c)(3) of the NGPA provides that determinations of a Federal or State agency shall be made in accordance with that agency's own procedures. The Statement of Managers of the NGPA states that any party aggrieved by procedural aspects of State or Federal agency determinations may pursue whatever appeal rights are otherwise available under State or Federal law. S. Rep. No. 95–1126, 95th Cong., 2d Sess. 119 (1978). Accordingly, comments concerning determination proceedings for withdrawn applications should be directed to the appropriate jurisdictional agency.

Comment Procedure

Any interested person may submit data, views and comments concerning this proposed rulemaking. Such comments should be addressed to the Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, and should not be submitted later than September 15 1979. An original and 14 conformed copies should be filed with the Commission, and should reference Docket No. RM79–66. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 N. Capitol Street, N.E., Washington, D.C., during regular business hours.

Public Hearings

The Commission intends to hold consolidated public hearings on these and other proposed NGPA rulemakings, as required by section 502(b) of the Act. The dates and locations of such hearings will be announced shortly. The regulations proposed in this Notice shall not become final until the Commission has had an opportunity to receive oral presentation of relevant data, views and arguments.

(Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.* E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, P.L. 95–621, 92 Stat. 3350)

In consideration of the foregoing, Part 275 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is proposed to be amended as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

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[1] The proposed regulation is not intended to apply to a case in which a seller withdraws an application for a determination from a jurisdictional agency. Treatment of such withdrawal would be a matter within the procedural discretion of the agency. We note, however, that if a jurisdictional agency permits a seller to withdraw an application, interim collection authority under § 273.202 terminates, and any subsequent application for the same well is subject to § 273.202(e), which provides that once interim collection authority under § 273.202 terminates, further filings under that section cannot be made for the same well.

§ 275.202 [Amended]

1. Section 275.202 is amended in paragraph (a) by deleting the phrase, "Except as provided in paragraph (b) of this section," and by substituting in lieu thereof the phrase, "Except as provided in paragraphs (b) and (c) of this section".

2. Section 275.202(b) is amended in subparagraph (2) to read as follows:

* * * * *

(b) *Incomplete notice.* Notwithstanding the provisions of paragraph (a) of this section, the 45-day period for Commission review of a determination shall not begin if:

* * * * *

(2) the Commission notifies the jurisdictional agency, the purchaser and the parties to the proceeding before the jurisdictional agency, within 45 days after the date on which the Commission receives notice of the determination, that the notice is incomplete.

* * * * *

3. Section 275.202 is amended by redesignating paragragh (c) as paragraph (d) and by inserting a new paragraph (c), to read as follows:

* * * * *

(c) *Withdrawal of Notice.* (1) The jurisdictional agency may withdraw a notice of determination by notifying the Commission, by letter or telegram, that the notice is withdrawn, and by stating the reasons for the withdrawal. The Commission must receive actual notice of the withdrawal within 40 days of the date on which it received the notice of determination.

(2) Within 5 days of receiving notification of a withdrawal, the Commission shall notify the parties to the proceeding before the jurisdictional agency and the purchaser of the withdrawal.

(3) The Commission shall also publish notice of the withdrawal and the reasons therefor in the Federal Register.

(4) Withdrawal of a notice of determination shall nullify such notice of determination.

* * * * *

¶ 32,032 Floodplain Management and Protection of Wetlands

44 F. R. 49466 (August 23, 1979).

[18 CFR Parts 2, 131, 156, 157]

[Docket No. RM 79-70]

Floodplain Management and Protection of Wetlands

Issued: August 20, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission is amending its regulations to implement Executive Order Nos. 11988 and 11990, respectively entitled Floodplain Management and Protection of Wetlands. The proposed amendments would operate in conjunction with the Commission's proposed regulations implementing the National Environmental Policy Act. The proposal in this docket would guide applicants under the Natural Gas Act and the Federal Power Act in evaluating the impact of the proposed projects on floodplains and wetlands and in supplying information on those projects to the Commission and the public. The proposal also directs applicants to avoid new construction in these environmentally sensitive areas, were applicable. In complying with the spirit of the Executive Orders, the propcsed amendment would help minimize health hazards and environmental damage in wetland areas or where there exists a substantial risk of flood loss.

DATE: Written comments by September 17, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC. 20426. Reference Docket No. RM79-70.

FOR FURTHER INFORMATION CONTACT: James Hoecker, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8106, 825 North Capitol Street, NE., Washington, DC. 20426. Phone (202) 275-0422.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) gives notice that it proposes to amend its Regulations to implement Executive Order Nos. 11988 and 11990 respectively entitled Floodplain Management and Protection of Wetlands. The proposed amendments would operate in conjunction with the Commission's proposed regulations implementing the National Environmental Policy Act to guide applicants in evaluating the impact of proposed projects on floodplains and wetlands and in supplying information on those projects to the Commission and the public.

Background

The proposed regulations would implement the provisions of Executive Order No. 11988—Floodplain Management and Executive Order No. 11990—Protection of Wetlands. Both executive orders concern actions of Federal agencies taken to protect wetlands and floodplains. Although the Commission, as an independent regulatory agency, is not bound by the executive orders, it has for many years taken into account in its decisionmaking processes, the potential impact on floodplains and wetlands. It has also determined that implementing procedures which reflect the provisions and policies of those orders, consistent with its independent regulatory functions, is in the public interest.

Section 1 of E.O. 11990, Protection of Wetlands, provides, in pertinent part:

> Each agency shall provide leadership and shall take action to minimize the destruction, loss or degradation of wetlands, and to preserve and enhance the natural and beneficial values of wetlands in carrying out the agency's responsibilities for . . . conducting Federal activities and programs

affecting land use, including but not limited to water and related land resources planning, regulating, and licensing activities.

Section 5 of E.O. 11990 provides:

In carrying out the activities described in Section 1 of this Order, each agency shall consider factors relevant to a proposal's effect on the survival and quality of the wetlands. Among these factors are: (a) public health, safety, and welfare, including water supply, quality, recharge and discharge; pollution; flood and storm hazards; and sediment and erosion;

(b) maintenance of natural systems, including conservation and long term productivity of existing flora and fauna, species and habitat diversity and stability, hydrologic utility, fish, wildlife, timber, and food and fiber resources; and

(c) other uses of wetlands in the public interest, including recreational, scientific, and cultural uses.

Although E.O. 11990, by the terms of Section 1(b), does not apply to the issuance of permits, licenses, or allocations to private parties for activities involving wetlands on non-Federal property, the Commission proposes, pursuant to its general responsibilities under the National Environmental Policy Act, to apply certain environmental review requirements to applications involving new construction on non-Federal, as well as Federal, wetlands. Existing environmental regulations require some wetlands information, and the Commission has long sought that information in its proceedings. However, the proposed regulations would serve to underscore explicitly the additional data requirements necessary to identify and protect these environmentally sensitive areas within the NEPA processes described in Docket No. RM79-69.

Section 1 of E.O. 11988, Floodplain Management, provides, in pertinent part:

Each agency shall provide leadership and shall take action to reduce the risk of flood loss, to minimize the impact of floods on human safety, health and welfare, and to restore and preserve the natural and beneficial values served by floodplains in carrying out its responsibilities for . . . (3) conducting Federal activities and programs affecting land use, including but not limited to water and related land resources planning, regulating, and licensing activities.

Section 2(c) of E.O. 11988 specifically addresses the responsibilities of licensing agencies:

(c) Each agency shall take floodplain management into account when formulating or evaluating any water and land use plans and shall require land and water resources use appropriate to the degree of hazard involved. Agencies shall include adequate provision for the evaluation and consideration of flood hazards in the regulations and operating procedures for the programs . . . that they administer. Agencies shall also encourage and provide appropriate guidance to applicants to evaluate the effects of their proposals in floodplains prior to submitting applications for Federal licenses, permits, loans or grants.

In keeping with the spirit of E.O. 11988, this Notice of Proposed Rulemaking will be transmitted to the Water Resources Council, the Federal Insurance Administration, and the Council on Environmental Quality with a specific request for their comments on these proposed regulations.

The Floodplain Management Guidelines for Implementing E.O. 11988 issued by the U.S. Water Resources Council recognize "the responsibility for individual agencies to tailor their procedures to meet both their legislatively prescribed missions and the requirements of the Order." Accordingly, the Commission is proposing these regulations in a form applicable to its independent regulatory decisionmaking procedures.

Discussion of the Proposed Regulations

The purpose of the proposed rule is to provide applicants with guidance to evaluate the effects of their proposed actions on floodplains and wetlands prior to the submission of applications for Commission approval. Furthermore, proposed amendments would require applicants to provide the Commission with sufficient information to evaluate any impact that would result from siting a proposed action in a floodplain or wetland, any flood hazard that might

result, and siting alternatives that should be considered. The proposed amendments would require early public notice in the local area likely to be affected by a proposed action under section 7 of the Natural Gas Act which would affect a floodplain or wetland.

The proposed amendments reflect an expansion of the requests for environmental data explicitly required for an applicant's Environmental Report to the Commission, in compliance with the National Environmental Policy Act, to include information on any floodplains and wetlands affected. The key provisions proposed are those included under Part 2, Appendices A and B, "Components of an Environmental Report." Under the proposed amendment, floodplains and wetlands information would have to be provided in all applications for which an Environmental Report is required.[1]

A number of provisions in existing and proposed regulations currently require environmental information that include much of the information required under both the Floodplain Management and the Protection of Wetlands executive orders. Numerous provisions require an assessment of the impact on ecosystems and habitats including floodplains and wetlands, in the area of the proposed action. Applicants must set forth possible natural catastrophes as well as implications of a proposed action for human health and safety. The several revisions proposed by this rulemaking make explicit that the more general terminology used throughout the Components of an Environmental Report and other regulations ought to include the floodplains and wetlands considerations enunciated in E.O. 11988 and E.O. 11990. Section 2.13 is amended to include avoidance of floodplains and wetlands in the design and construction of projects under the Federal Power Act as a policy to be followed where practical. Likewise, these areas are to be avoided by gas pipeline construction and operation, where practical, under amendments to § 2.69.

Executive Orders 11988 and 11990 call for public notice and an opportunity for early public review of proposed actions in floodplains and wetlands. Current Commission procedures under Sections 4 and 6 of the Federal Power Act (16 U.S.C. 797 and 799) require public notice upon the filing of relevant water power project applications (§§ 3.113–.114). In addition to the required notice in a newspaper in the county or counties affected, the Commission also publishes notice in the **Federal Register** and gives specific notice to any State or municipality likely to be interested. However, under the proposed amendments, the notice would be expanded to mention specifically floodplain and wetlands considerations in the description of the proposed action. Thus, there is no need for a revision of publication procedures which currently apply to applications made under the Federal Power Act.

With respect to applications under the Natural Gas Act, current notice requirements are embodied in §§ 156.8 and 157.9 of the Commission regulations. These requirements provide for notification of affected states and publication in the **Federal Register**. The present rulemaking proposes to expand those provisions in cases where a floodplain or wetland is involved to include notice to affected municipalities and publication of notice in the affected local area. Similar to the proposed treatment of applications under the

[1] Under Docket No. RM79-69, Appendices A and B will be transferred to proposed Part 3d, Regulations Implementing the National Environmental Policy Act. Appendix B will continue to apply to all applications under the Natural Gas Act, but Appendix A is being replaced by Environmental Report sections in new water power project licensing provisions and will apply only to major unconstructed water power projects until §§ 4.40 through 4.42 are revised and Appendix A is eliminated. Environmental Reports will be required for projects under Part I of the Federal Power Act, and under § 7(c) of the Natural Gas Act, according to § 3d.12 of the proposed NEPA regulations. Therefore, the "abbreviated application" permitted by the appendices will not be permitted, and is proposed to be eliminated in Docket No. RM79-69.

Federal Power Act, the content of the notice would be expanded to reflect floodplains and wetlands considerations based on the information required in environmental reports filed as part of the application under the Natural Gas Act.

Related Rulemaking Proceedings

The Commission has proposed regulations to in Docket No. RM79-36, reform the license application for major water power projects [more than 1.5 MW or 2,000 horsepower] at existing dams. As in Phase I of the Commission's reform of water power project licensing,[2] an environmental report commensurate with the scope of the project is prescribed in the regulations in Docket No. RM79-36. While the proposed rule set forth below would amend the Environmental Report in § 131.6 to alert the applicant for a license for a minor water power project to the policy of protecting floodplains and wetlands, the Commission also gives notice that it will include similar language in the Environmental Report requirements which will be adopted in Docket No. RM79-36. Proposed Exhibit E in § 4.51(f) will be revised in subparagraphs (1) and (6) to reflect the concerns of this rulemaking as follows:

(f) * * *

(1) *General description of locale.* The applicant must provide a general description of the environment of the project and its immediate vicinity. The description must include general information concerning climate, topography, *wetlands,* vegetative cover, land development, population size and density, *the presence of any floodplains and the occurrence of flood events in the vicinity of the project,* and any other subjects helpful to an understanding of the setting.

* * * * *

(6) *Report on land management and aesthetics.* The applicant must provide a report on the management of land within the proposed project boundary, *including wetlands and floodplains,* and the protection of the scenic values of the project. * * * The report must contain:

* * *

(vi) *a description of wetlands or floodplains within or adjacent to the project boundary, any short- or long-term impact from the project on those wetlands or floodplains, and any alternatives to the project or mitigative and restorative measures considered by the applicant, including flood minimization measures. (Underlining* for emphasis only.)

The Commission will also insert language in its final Regulations Prescribing General Provisions for Preliminary Permit and License Applications, Docket No. RM79-23, to reflect the concerns of this rulemaking. Proposed § 4.81(c)(2)(i) of that docket will be amended to read:

(i) a description, including the approximate location, of any activity that would alter or disturb lands or waters in the vicinity of the proposed project, *including floodplains or wetlands,* and measures that would be taken to minimize any such disturbance and measures to restore altered or disturbed areas.

Appendix A of Part 2, which is amended by this rulemaking, will constitute the Environmental Report for major unconstructed water power projects after Docket No. RM79-36 is issued as a final rule by the Commission. As stated in footnote 2, Appendices A and B will be transferred to Part 3d of the regulations by the NEPA rulemaking, Docket No. RM79-69. However, Appendix A will be eliminated when the licensing procedures for major unconstructed water power projects are revised, because at that time a separate Environmental Report requirement will be included in the regulations applicable to such projects.

Comment Procedure

Interested persons are invited to submit written comments, data, views,

[2] Simplified Procedures for Certain Water Power Licenses, Order No. 11, September 5, 1978 (Docket No. RM78-9).

suggestions, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC. 20426, and should reference Docket No. Rm79–70. An original and 14 copies should be filed. All comments received by September 17, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be place in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capital Street, NE., Washington, DC., during regular business hours.

(National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321–4347; Federal Power Act, 16 U.S.C. 792–828c; Natural Gas Act, 15 U.S.C. 717–717w; Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; Executive Order 12009, 42 FR 46267.)

In consideration of the foregoing, the Commission proposes to amend Parts 2, 131, 156, and 157 of Chapter I, Title 18, Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 2.13 is amended by adding a paragraph (d) to read as follows:

§ 2.13 Design and construction.

* * * * *

(d) Where practical, proposed actions should avoid locations involving wetlands or floodplains.

2. Section 2.69 is amended by revising paragraph (a)(1)(iii) and by adding clause (x) to paragraph (a)(3) to read as follows:

§ 2.69 Guidelines to be followed by natural gas companies in the planning, locating, clearing, and maintenance of right-of-way and the construction of aboveground facilities.

(a) * * *

(1) *Pipeline construction.* * * *

(iii) Rights-of-way should avoid heavily timbered areas, steep slopes, wetlands, and floodplains, where practical.

* * * * *

(3) *Construction of aboveground appaurtenant facilities.*

* * * * *

(x) Where practical, aboveground facilities should not be sited in wetland or floodplain areas.

3. Appendices A and B of Part 2 are amended in paragraph 1.2 of the "Components of an Environmental Report" of each by adding the following at the end thereof:

State specifically whether the proposed action would involve new construction within a floodplain as defined in Executive Order No. 11988 (42 FR 26951, May 25, 1977) or a wetland as defined in Executive Order No. 11990 (42 FR 26961, May 25, 1977). Provide U.S. Department of Housing and Urban Development floodplain maps or other "best available" information to indicate which portions of the proposed action would involve new construction within a floodplain or wetland as defined above.

4. Appendices A and B of Part 2 are amended in paragraph 2.4.2 of the "Components of an Environmental Report" of each by adding the following at the end thereof:

Describe flood events and other pertinent environmental factors in sufficient detail to support an analysis of the proposed action's impact on the floodplain and any hazards created by its location in the floodplain.

5. Appendices A and B of Part 2 are amended in paragraph 4 of the "Components of an Environmental Report" of each by inserting the words "flood hazard minimization," after the word "including".

6. Appendices A and B of Part 2 are amended in paragraph 8.3 of the "Components of an Environmental Report" of each by revising the first sentence to read as follows:

8.3 *Sites and locations*—Dicuss considerations given to alternative sites and locations, including those sites and locations that would avoid or minimize impacts on floodplains or wetlands.

7. Section 131.6 is revised in paragraph (3) of the Environmental Report to read as follows:

§ 131.6 Application for short-form license (minor).

* * * * *

Environmental Report. (1) * * *

(2) * * *

(3) A description of the expected environmental impact resulting from the continued operation of an existing project, or from the construction and operation of a new project or a project using an existing dam or other existing facility, including attention to the consequences of project construction and operations for any floodplains or wetland areas. Include a discussion of specific measures (including the cost of those measures and the party undertaking to implement those measures if other than the applicant) proposed by the applicant and others which would: (i) protect and enhance environmental resources; (ii) mitigate adverse impacts on environmental resources and values; and (iii) minimize any flood hazards.

§§ 156.8, 157.9 [Amended]

8. Section 156.8 and § 157.9 are amended by adding a sentence at the end of each to read:

When an application proposes an action within a floodplain or wetland area, approporiate notice will be published in a newspaper of general circulation in the county or counties that would be affected by the proposed action.

¶ 32,033 Procedures Governing Applications for Special Relief Under Sections 104, 106 and 109 of the Natural Gas Policy Act of 1978

44 F. R. 49468 (August 23, 1979).

[18 CFR Parts 2 and 271]

[Docket No. RM79-67]

Procedures Governing Applications for Special Relief Under Sections 104, 106 and 109 of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Because the Natural Gas Policy Act of 1978 (NGPA) has superseded the special relief and optional certificate procedures formulated under the Natural Gas Act (NGA), the Commission is considering promulgating regulations for special relief under sections 104, 106, and 109 of the NGPA and deleting its special relief regulations formulated under the NGA.

DATES: Comments are due on or before September 14, 1979.

ADDRESS: Send comments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capital Street, N.E., Washington, D.C. 20426. Comments should reference Docket No. RM79-67 on the outside of the envelope and on all documents submitted to the Commission.

FOR FURTHER INFORMATION CONTACT:

Jane Phillips, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8104-B, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202)275-0422.

Louis Engel, Division of Producer Rates and Certificates, Federal Energy Regulatory Commission, Room 6300, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202)275-4539.

Issued August 14, 1979.

Background

On the effective date of Title I of the Natural Gas Policy Act of 1978 (NGPA), P.L. 95-621, the Federal Energy Regulatory Commission (Commission) issued an Order With Respect To Optional Procedure Cases.[1] The order notified producers that the NGPA had superseded the special relief and optional certificate procedures formulated under the Natural Gas Act (NGA) and that the Commission intended to issue a transitional rule with respect to pending optional procedure cases. The regulations here proposed govern the granting of special relief under the NGPA for new applications and pending special relief and optional procedure applications filed under the NGA.

The proposed regulations, Subpart J of Part 271, would implement sections 104(b)(2), 106(c), and 109(b)(2) of the NGPA which provide that the Commission may, by rule or order, prescribe a maximum lawful price in excess of that prescribed by the respective sections if such price would be just and reasonable within the meaning of the NGA. The Commission's authority under these sections of the NGPA to grant such special relief is limited to gas committed or dedicated to interstate commerce on November 8, 1978, (section 104), gas sold under rollover contracts (section 106) and gas not covered by any other maximum lawful price under Title I of the NGPA (section 109). Gas qualifying under these sections would be eligible for special relief whether or not such gas also qualifies under other sections of the NGPA.

While the applicability of the proposed rulemaking is limited to gas qualifying under sections 104, 106 and

[1] Order With Respect to Optional Procedure Cases, (Docket Nos. CI76-590 *et al.*) (issued December 1, 1978) (regarding Appalachian Exploration and Development, Inc., *et al.*).

109 of the NGPA, the Commission specifically solicits comments on whether the scope of the regulations could or should be extended, through the authority granted to the Commission in section 107, to apply to gas subject to sections 102, 103, 105, and 108 of the NGPA. Section 107 of the NGPA authorizes the Commission to prescribe maximum lawful prices to the extent necessary to provide reasonable incentives for the production of "high cost natural gas" and to determine under subsection (c)(5) of that section what gas shall be considered to be high cost natural gas because "produced under such * * * conditions as the Commission determines * * * present extraordinary risks or costs." Presumably, an extension of special relief to gas qualifying only under sections 102, 103, 105, and 108, if deemed permissible or advisable, would be accomplished through use of the Commission's authority under section 107. In addition, the Commission solicits comments as to whether it has authority under section 110 of the NGPA to allow the equivalent of a special relief rate as a production-related cost for gas subject to sections 102, 103, 105, and 108.

As proposed, the regulations prescribe the circumstances under which a first seller of natural gas may seek a special relief rate, the manner in which the application is to be made, the cost standards which will be used in determining the special relief rate, and the procedures by which the application will be reviewed and decided.

The Federal Power Commission (FPC) considered special relief initially in the first area rate proceeding, *Permian Basin Area Rate Proceeding (Permian I).*[2] It was to act as a "safety valve" for producers for which gas sales at the applicable area rates would amount to an unconstitutional taking of private property without due process.[3]

In 1974 the FPC issued Opinion No. 699,[4] which established nationwide rather than areawide rates. Neither in the area rate opinions nor in Opinion No. 699, did the FPC indicate what special circumstances, other than the "out-of-pocket" expense test, would qualify gas sales for special relief. The rules governing special relief were codified at 18 C.F.R. § 2.56a(g).

Opinion No. 749, issued in 1975,[5] authorized special relief for older vintage "flowing gas." This rule was codified at 18 CFR § 2.56b(h) and used the "out-of-pocket" expense standard. In 1976, the FPC issued Opinion No. 770–A establishing the second biennial national rate. The concept of special relief was upheld judicially [6] and was codified at 18 C.F.R. §§ 256a(g).

During the early 1970's the FPC established three other broad categories of "special relief." Order No. 481 [7] adopted a special relief procedure as an alternative to abandonment for wells nearing their economic limit. This procedure, codified at 18 CFR § 2.76, allowed recovery of added investment necessary to keep the well in production. This standard was less stringent than the "out-of-pocket" test used in the national rate opinions which allowed only recovery of operating costs. In 1973 the FPC issued Order No. 482 [8] establishing a special relief provision, codified at 18 CFR § 2.77, to induce sales of gas which would otherwise be flared. No applications have been made to date under this procedure. The FPC promulgated the optional certificate procedure, codified at 18 CFR § 2.75, in 1972 as an alternative to area ratemaking. Its purpose was to bring new, long-term dedications of gas into the interstate market by providing the incentives of higher rates and price certainty. As applied, this procedure allowed

[2] 34 F.P.C. 159 (1965), aff'd *sub nom.*, Permian Basin Area Rate Cases, 390 U.S. 747 (1968).
[3] Id. at 180, 226.
[4] 51 F.P.C. 2212, aff'd *sub nom.*, Shell Oil Co. v. FPC, 520 F.2d 1061.
[5] Aff'd *sub nom.*, Tenneco Oil Co. v. FERC, 571 F.2d 834.
[6] Tenneco Oil Co. v. FPC, (5th Cir., April 18, 1978.)
[7] 49 F.P.C. 992 (1973).
[8] 49 F.P.C. 996 (1973).

recovery of full costs of a gas supply project plus a 15 percent return.[9]

In conjunction with the regulations here proposed, the Commission proposes to delete from its current regulations §§ 2.56a(g), 2.56b(h), 2.75, 2.76, and 2.77. A pending application filed under any of these sections would be deemed to have been withdrawn for failure to go forward unless the applicant filed, within 30 days of issuance of the this proposed rule in final form, a notice of intent to proceed with its application under Subpart J. The applicant would also be required to conform the original application to the requirements of Subpart J.

Nature of the Proposed Regulations

The proposed regulations establish standards and procedures for the granting of special relief for gas subject to the maximum lawful prices prescribed in sections 104, 106, and 109 of the NGPA. These sections apply respectively to gas committed or dedicated to interstate commerce on November 8, 1978; gas sold under rollover contracts; and gas not covered by any other maximum lawful price under Title I of the NGPA.[10] In accordance with section 101(b)(5) of the NGPA (which provides that gas qualifying for more than one maximum lawful price or "any exemption from such a price" shall qualify for the highest applicable price), even if natural gas is also determined under Part 274 to be new natural gas (section 102), gas produced from new onshore production wells (section 103), high-cost natural gas (section 107) or stripper well gas (section 108), or if it is gas sold under an existing intrastate contract (section 105), it could still be eligible for a special relief rate.

Eligibility

In order to apply for special relief for a sale of natural gas, an applicant must be a first seller of the gas (rather than a reseller) and must have contractual authorization for the rate sought at the time the initial application is filed under Subpart J. Section 271.1004(b)(2) permits an applicant who originally filed an application under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 and 2.77 (old procedures) to continue the application under Subpart J. To do so, the applicant must file a notice of intent to proceed with the application under Subpart J and then file a conforming application or applications. The applicant may request a different rate than that initially requested so long as it has contractual authorization for the rate sought at the time the conforming application is filed.

By limiting applicants to "first sellers" the Commission intends to limit special relief under the proposed rules to producer costs. Resellers must seek relief under the Commission's adjustment procedures which implement section 502(c) of the NGPA and which are codified at 18 CFR § 1.41.

Section 271.1002(a) defines the production units for which a special relief application may be made and for which costs and reserves must be separately established in computing a special relief rate. They are:

A planned onshore well and related production facilities;
A planned offshore development well and related production facilities;
A planned offshore platform, wells drilled thereon and related production facilities;
Planned production enhancement work on a previously producing well; and
A well for which there is no planned investment.

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[9] *See, e.g.*, American Natural Gas Production Co., Order Granting Certificate of Public Convenience and Necessity (Docket No. CI77-657) (Dec. 5, 1978). Although the optional procedure was affirmed, Moss v. FPC 424 U.S. 494 (1976), no application has yet withstood judicial scrutiny. *See*, Consumers Union of U.S., Inc. v. FPC, 510 F.2d 656 (1974), *reversing* Belco Petroleum Corp., Opinion No. 659, 49 F.P.C. 1154 (1973) and Public Service Commission of New York v. FERC, No. 78-1352, (D.C. Cir., Sept. 23, 1978), *reversing* Pennzoil Producing Co., Opinion No. 752, 12 F.P.S. 5-385 (1978).

[10] The proposed regulations do not apply to gas under section 109(a)(4)—gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaskan Natural Gas Transportation Act of 1976.

Section 271.1003(a)(2)(ii), which limits the recovery of previously incurred (sunk) investment and operating expenses, indicates that a production unit would be characterized as involving or not involving planned investment based on its status at the time the application is accepted under Subpart J.[11]

Under the regulations as proposed, a first seller would make a separate special relief application for each planned investment project or each well for which there is no planned investment. The Commission believes that a separate rate should be established for each such project or well, rather than for an aggregate of projects or wells. This procedure would enable the Commission to focus more clearly and easily on the specific costs of producing the particular gas for which the special relief rate is sought and in estimating the available reserves of such gas. The Commission does not believe that this policy would place an undue burden on the applicant, because the cost and reserve information should be available and reportable on a project-by-project or well-by-well basis.

Standards for Special Relief Rate

Congress stated in sections 104, 106, and 109 of the NGPA that the Commission may increase the applicable maximum lawful prices so long as the higher price is "just and reasonable within the meaning of the Natural Gas Act."[12] The Commission believes that the method for calculating a special relief rate proposed in § 271.1003 adheres to this Congressional mandate.

Paragraph (a) of § 271.1003 establishes standards for determining the special relief rate for planned investment projects; paragraph (b) establishes standards where there is no planned investment. Both stipulate that only prudent expenditures shall be considered. Under the regulations, the special relief rate would consist of an amount computed in accordance with the standards provided in paragraphs (a) and (b), to which would be added the amount of taxes actually paid (exclusive of those adjustments allowed under Subpart K and section 110 of the NGPA and, in the case of planned investment projects, Federal income tax). The Commission has excluded adjustments allowed under Subpart K from consideration in the special relief rate because such adjustments are automatically allowed under § 271.1102.

The methodologies for computing the special relief rate with and without planned investment are different; this dichotomy reflects prior Commision practice. The rate for planned investment projects is to be computed using the discounted cash flow (DCF) method; the rate where there is no planned investment is not. However, the Commission is considering use of a DCF-type analysis in computing a special relief rate where there is no planned investment, as an alternative to employing the average-cost technique embodied in the regulations proposed in this rulemaking. Comments on the advantages and disadvantages of the approach contained in the proposal and on using the DCF method as an alternative are specifically requested.

Section 271.1003(a)(1) states that the special relief rate for gas sold from a planned investment project other than a small project shall allow the applicant to earn a 15 percent true yield on its expenditures related to the project. In Opinion No. 770–A, the FPC allowed a 15 percent overall rate of return which represented a 17.73 percent return on

[11] For applications filed under §§ 2.56(a)(g), 2.56(b)(h), 2.75, 2.76, or 2.77 and continued under this subpart, the production unit is to be characterized as of the date of that original filing.

[12] The enactment of the NGA in 1938 gave the Commission the authority to determine and fix "just and reasonable rates." § 5(a), 15 U.S.C. § 717d(a), for the "sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use. . . ." § 1(b), 15 U.S.C. § 717(b).

common equity.[13] The 15 percent rate was in line with returns for other extractive industries. It is the Commission's belief that this 15 percent rate of return continues to reflect the current financial requirements for special relief projects.

Section 271.1003(a)(1) also requires that the rate be determined using the DCF method. Historically, the Commission has relied upon the DCF cost analysis to assure that the rate allowed for gas supplies adequately reflects the true cost of those supplies.[14] The DCF methodology is predictive and focuses on anticipated cash flows over the life of the well rather than on revenues and costs for any one year. The commission continues to believe that the DCF cost method is a reliable basis for determining a just and reasonable rate where there is planned investment and intends to place a descriptive of the DCF method to be used by Staff in the public file for this proceeding.

Section 271.1003(a)(2)(ii) deals with previously incurred (sunk) investment and operating expenses and requires that sunk expenditures be excluded from consideration in determining a special relief rate. For pending applications, an applicant may not recover expenditures made prior to the time the application was filed under the old procedures. In the case of new applications the applicant may not recover expenditures made prior to the acceptance of the application. It is the Commission's belief that recovery of sunk exploration and development expenditures is not necessary to permit continued production from wells already explored and developed and could have adverse consequences. Mindful of the directive of the court to provide a *"demonstrable connection* between the funding in the (special relief) program under scrutiny and the increased gas supply which it will allegedly produce," (emphasis added), *Public Service Commission of the State of New York* v. *FERC*, No. 76-1352, Slip Op. at 15 (D.C. Cir., Sept 28, 1978), the Commission will look at the project prospectively and will so limit acceptable expenditures. The Commission specifically solicits comments on the portion of the regulations relating to sunk expenditures.

Section 271.1003(a)(2)(iii) limits the time lapse between commencement of the planned project and the earliest date of deliveries attributable to the project to one year unless adequate justification is shown for a longer period. Based on past experience with the types of projects usually undertaken, the Commission believes that such projects should be completed within one year. By placing a one year restriction on special relief projects, the Commission is recognizing the time value of money, and is attempting to avoid unnecessary increases in expenses due to unnecessary time delays in completing a project.

Section 271.1003(a)(2)(iv) provides for the recovery of Federal income taxes (FIT). FIT is a component of the DCF cost analysis and as such is included in establishing the special relief rate. Recovery of FIT is based on the marginal effective tax rate attributable to income from the project. In most

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[13] Opinion No. 770, as amended, was affirmed in The Second National Natural Gas Rate Cases, American Public Gas Rate Cases, American Public Gas Association, et al. v. F.P.C., (D.C. Cir. 1977), 555 F.2d 852. The 15 percent rate of return, also used by the Commission in Opinion No. 749, as amended, was upheld in Tenneco Oil Co. v. FERC, 571 F.2d 834, (Cir. 19—), where the court concluded that the Commission's choice of rate was "reasonable." The 15 percent rate of return was previously used in Opinion No. 699-H and upheld by the court in Shell Oil Co. V. FPC, 520 F.2d 1061, (5th Cir., 1975) where the court found "that the Commission carefully evaluated average rates of return on capital invested in other industries and concluded that a zone of reasonableness spanned from 12 percent to 15 percent." The selection of the highest rate of return within the zone was based on the desire to provide the extra incentive which the Commission felt was needed to encourage increased exploration and development.

[14] The DCF cost analysis methodology was applied and upheld, *inter alia*, in Opinion Nos. 699-H and 770-A.

cases, this will be the statutory tax rate; [15] in some cases, however, this tax rate would be decreased by the impact of percentage depletion allowances and investment tax credits. The Commission has selected the marginal effective tax rate in calculating the tax component in the DCF cost analysis because it believes that an applicant, when evaluating whether to undertake a given project, will include in its analysis the effect of projected income on the applicant's tax cost. This tax cost effect is measured by applying the marginal effective tax rate to the expected taxable income from the project. The Commission is specifically soliciting comments on this portion of the regulations and also seeks comments on what tax treatment should be accorded under this method to individuals and partnerships.

Section 271.1003(a)(2)(v) determines the manner in which operating expenses will be determined for the life of the project. The rule requires an applicant to estimate such expenses over the life of the project and provides an alternative methodology for applicants unable to make such an estimate. Under that alternative, an applicant would estimate its operating expenses for the first year in which deliveries would be made under the special relief rate, subtract production, *ad valorem*, income taxes and any other Subpart K adjustments from that amount, and escalate the resulting amount by seven percent compounded yearly for each year subsequent to the first year. Historically, the Commission has adjusted operating expenses by five percent for a five-year period. However, it is the Commission's judgment that a seven percent rather than a five percent escalation for the life of the project is now reasonable because of recent increases in inflation.

Section 271.003(a)(2)(vi) establishes the appropriate formula for determining regulatory expense. The formula is based on prior Commission practice which, in the judgment of the Commission, should be continued.

Section 271.1003(a)(vii) permits a working capital allowance of 12.5 percent of operating expenses (excluding production, *ad valorem*, income taxes and any other Subpart K adjustments). This provision is likewise based on prior Commission practice which the Commission believes should be continued with respect to gas sales.

Paragraph (b) of § 271.1003 specifies that the special relief rate for a well for which there is no planned investment shall be the rate under which it is predicted that the applicant will recover those normal, recurring operating and maintenance expenses which reasonably can be assigned to gas production, other than those adjustments permitted under Subpart K.

The Commission is considering some alternative ways of calculating the special relief rate and invites comments on those alternatives. For wells without planned investment and where out-of-pocket costs cannot be estimated for the life of the project, the proposed regulations contemplate a single average price to be calculated by inflating out-of-pocket costs for the first year by a given rate of inflation and dividing total costs by the total expected future output of the well. As an alternative, the Commission is considering a procedure whereby the Commission would approve a schedule of monthly prices for each year of the estimated remaining production life of the well. The schedule would be determined by estimating for the first year of deliveries the normal, recurring our-of-pocket expenses, on a per unit of current output basis. The price for each successive year's production would then be calculated by applying the rate of expected depletion of the well to the base price. Applicants could determine the maximum lawful price for gas from the well for each

[15] In Opinions 770 and 770-A, the Commission used the statutory tax rate of 48 percent in arriving at the national rate. (The statutory tax rate for corporations is now 46 percent.) In Columbia Gulf Transmission Co., *et al.*, Docket Nos. RP75-105, *et al.*, Opinion No. 47, the Commission approved the "stand-alone" basis for each pipeline in preference to the consolidated approach.

month by applying to the price schedule the monthly inflation rate specified in Title I of the NGPA and published by the Commission. This methodology would insure a price each year that would cover current out-of-pocket costs plus inflation.

A similar price schedule, or "tilt," would be applied to gas from a planned investment project, the average price for which is to be calculated under the proposed rule using the DCF method. The Commission invites comments from all parties regarding the use of these alternative methodologies.

Application Procedure

Sections 271.1004 and 271.1010 establish when and in what manner an applicant must file for special relief. Sections 271.1005 through 271.1008 describe Commission procedures for reviewing the application and provide for intervention in the proceeding. Section 271.1009 provides for retroactive collection of the special relief rate.

Under the proposed rules applicants having planned investment projects (except those qualifying as small projects) would be required to make two applications. The first would be made prior to commencing the project. The information required to be filed is specified in § 271.1010 (a) and (b). The initial application would be reviewed by Staff (which by definition excludes the Director of the Commission's Office of Pipeline and Producer Regulation [Director]). Staff action (other than notification of deficiencies or requests for additional information) could be appealed to the Commission. Acceptance of the application would authorize the applicant to include all future expenditures for the project in its supplemental application which must be filed within 60 days of completing the project.

The Commission has provided special provisions for planned investment projects qualifying as small projects under § 271.1006(d)(1)(ii). Applicants for such projects are required to file only the initial application, approval of which by the Director (or the Commission in the case of an appeal) would authorize the applicant to begin charging the approved rate upon completion of the project. This abbreviated procedure for small projects is consistent with the Commission's policy of promoting administrative efficiency by not examining in as great detail those actions the impact of which is so minimal as to require a correspondingly lesser degree of Commission scrutiny.

However, the Commission emphasizes that Staff may perform such audits on small projects as it deems appropriate under § 271.1006(f). The criteria for a small project are essentially the same as those used in § 2.76, adjusted for inflation. The project must result in additional revenues of less than $60,000; the proposed investment must exceed 25 percent of the estimated additional revenues to be generated under the special relief rate; and the total proposed rate must be no more than 60 cents per MMBtu, exclusive of State severance taxes as defined in § 271.1101(a).

The procedures for reviewing a supplemental application for a planned investment project and initial applications for small projects and wells for which there is no planned investment are the same because, in all three cases, the procedure results in a determination of a special relief rate.

Under those procedures, set forth in § 271.1006(d), the Staff could reject the application for failure to conform to the regulations or issue a Staff report to the Director recommending a special relief rate and stating the basis for its recommendation. Paragraph (f) of § 271.1006 specifies what powers the Staff may exercise in gathering the information necessary to evaluating the application and recommending a special relief rate. The Staff is given the power to conduct field audits, to solicit information from the applicant and other sources and to conduct conferences. Use of such powers will be necessary, in many instances, to permit a determination of whether expenditures are prudent.

The applicant, any intervenors, and certain other parties may submit comments on the Staff report. These comments will be reviewed by the Director, together with the Staff report, prior to the Director's issuing a determination on the application. Under § 271.1007(b), the Director's determination will become final 30 days after notice of it is published in the **Federal Register** unless the Commission directs or a petition is received requesting Commission review of the Director's determination.

Under § 271.1008 the Commission will normally review the case based on the record compiled by the Staff and the Director. Although the NGPA does not require an evidentiary hearing for special relief applications, the Commission anticipates that in some cases it will require additional information in order to act on an application and that it may wish to provide for a hearing for such purpose. This hearing will not necessarily be the kind required for adjudications under sections 554, 556, and 557 of the Administrative Procedure Act.

Because the Commission considers special relief to have a great impact on consumers and pipelines as well as producers, it has provided for public notice and participation at each stage of the proceeding. Under § 271.1004(d), notice of any application must be published in the **Federal Register** and a copy of the application must be served on each purchaser. The Commission has also provided an opportunity for intervention under § 271.1005. Section 271.1006(b) (regarding Staff decisions) and § 271.1007(c) (regarding the Director's determination) require that notice of Staff and Director actions be served on all persons entitled to service of an application and on all intervenors.

All such persons may attend any conference conducted by the Staff under § 271.1006(f), may submit comments on the Staff report issued under § 271.1008(d)(2)(iii) and may appeal Staff and Director actions to the Commission under § 271.1008.

The information to be filed in an initial application for a planned investment project other than a small project is specified in paragraphs (a) and (b) of § 271.1010; information required for the supplemental application is specified in paragraph (e) of that section. Information required for small projects is specified in paragraph (d) of that section, for wells for which there is no planned investment, in paragraph (c) of that section. In general, initial applications must include the proposed price; evidence of contractual authorization to collect such price; estimated reserves and annual production, geological data and a financial justification for the proposed price; and, in the case of a planned project, detailed plans for the project including targeted commencement and completion dates; and the allocation of estimated investment and expenses. Supplemental applications must contain similar information except that a detailed description of the completed rather than the proposed project is required.

Applications filed under §§ 2.56a(g), 2.56b(h), 2.75, 2.76, and 2.77 prior to the effective date of Subpart J will be processed in accordance with the requirements in Subpart J. Section 271.1004(d)(1) requires an applicant who wishes to proceed with such application under Subpart J to file a notice of such intent within 30 days of the issuance of the proposed rule in final form or its application shall be deemed withdrawn. This procedure will enable the Commission to assess which and how many applications it must process. Automatic withdrawal of an application would require an applicant to file a new application and would preclude recovery of costs incurred between the time the old application was originally filed and the time the new one was accepted. It would also affect adversely the applicant's rights to retroactive collection of the special relief rate under § 271.1009. Under subparagraph (3) of § 271.1004(d), the applicant must either conform its old application to the requirements of Subpart J where

necessary or file a statement indicating that it believes the old application conforms to the requirements of Subpart J and that it wishes the application to be evaluated as originally submitted. Subparagraph (5) of § 271.1004(d) specifies the filing requirements for planned investment projects for which application was made under the old procedures and which were completed prior to the issuance of this proposed rule in final form.

Interim and Retroactive Collections

Section 271.1002(d) provides that neither the filing nor the pendency of an application for special relief under Subpart J shall prohibit the applicant from collecting the otherwise applicable maximum lawful price under the NGPA for sales made from the planned investment project or from the well for which there is no planned investment.

Section 271.1009 provides for retroactive collection of the approved special relief rate. For all applications filed under § 2.75, collection of the approved special relief rate would be permitted retroactive to the date nine months following commencement of deliveries under the contract to which the rate applies. This provision parallels collection rights under § 2.75 as it was in effect on December 1, 1978. However, because an applicant who filed under §§ 2.56a(g), 2.56b(h), 2.76 or 2.77 had no right to retroactive collection or collection during the pendency of the proceeding, it will only be able to collect the approved rate for a well without planned investment retroactive to the date of filing the notice of intent and, in the case of a planned investment project, retroactive to the later of the date of the notice filing or commencement of deliveries. Where there is no planned investment, a new applicant would be permitted to collect the approved rate retroactive to the date the initial application was filed under Subpart J. New applicants with planned investment projects would be able to collect the approved special relief rate beginning on the date deliveries were initiated. The Commission believes that it is necessary to provide for retroactive collection so that a producer who is losing or may lose money on a well and who is entitled to special relief will not be encouraged to refrain from producing from the well until the special relief rate is approved and made effective.

Written Comments

Interested persons are invited to submit written comments on the proposed regulations to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Comments should reference Docket No. RM79–67 on the outside of the envelope and on all documents submitted to the Commission. The Commission requests that persons submitting comments identify specifically the section addressed, particularly for those issues on which the Commission has specifically solicited comments.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission on or before September 14, 1979, will be considered prior to the promulgation of final regulations.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. § 7107 *et seq.*; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, it is proposed to amend Parts 2 and 271 of Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Part 2 is amended in the Table of Contents where appropriate and in the text of the regulations by deleting §§ 2.56a(g) 2.56b(h), 2.75, 2.76, and 2.77. Paragraphs (h) through (p) of § 2.56a are redesignated as paragraphs (g) through (o). Paragraphs (i) through (n) of § 2.56b are redesignated as paragraphs (h) through (m).

2. Part 271 is amended in the Table of Contents by deleting "Subpart J—[Reserved]" and substituting the following in lieu thereof:

Subpart J—Special Relief

Sec.
271.1001 Applicability.
271.1002 Eligibility.
271.1003 Special relief rate.
271.1004 Application.
271.1005 Intervention.
271.1006 Review by Staff.
271.1007 Determination by the Director of the Office of Pipeline and Producer Regulation.
271.1008 Appeals to the Commission.
271.1009 Retroactive collection.
271.1010 Filing requirements.

Authority: Natural Gas Act, as amended, 15 USC § 717 *et seq.*; Natural Gas Policy Act of 1978, P. L. 95-621, 92 Stat 3350; Department of Energy Organization Act, 42 U.S.C. § 7107 *et seq.*; E.O. 12009, 42 Fed. Reg. 46267.

3. Part 271 is further amended in the text of the regulations by deleting "Subpart J—(Reserved)" and substituting the following in lieu thereof:

Subpart J—Special Relief

§ 271.1001 Applicability.

This subpart sets forth the conditions under which special relief may be obtained for any natural gas which is subject to a maximum lawful price under section 104, 106, or 109 of the NGPA (whether or not such gas qualifies under any other section of the NGPA), except that this subpart does not apply to natural gas produced from the Prudhoe Bay unit of Alaska.

§ 271.1002 Eligibility

(a) *Eligibility.* A first seller may apply for a special relief rate under this subpart for natural gas produced from any of the following:

(1) A planned investment project as defined in paragraph (c) of this section; or

(2) A well for which there is no planned investment.

(b) *Contractual authorization.* In order to apply for a special relief rate under this subpart, a first seller must have contractual authorization to charge and collect the specific special relief rate (in cents/MMBtu) proposed in its application at the time a filing is made under § 271.1004 (b)(1) or (d)(3) with the Commission.

(c) *Definitions.* For purposes of this subpart:

(1) "Planned investment project" means:

(i) A planned onshore well and related production facilities;

(ii) A planned offshore development well and related production facilities;

(iii) A planned offshore platform, wells drilled thereon and related production facilities; or

(iv) Planned production enhancement work on a previously producing well.

(2) "Related production facilities" means the equipment and facilities of the first seller which connect the wellhead to the purchaser's facilities.

(3) "Production enhancement work" means work in the nature of reconditioning, workover, deeper drilling, replacing or adding major equipment or related production facilities, or any other additional work necessary to prevent the loss of gas production or reserves.

(4) "First seller," for purposes of this subpart, shall exclude a reseller as defined in § 270.202(e)(2) of this chapter.

(d) *Rates for sales during pendency of special relief application.* Neither the filing nor the pendency of an application for special relief under this subpart shall prohibit the applicant from collecting the applicable maximum lawful price under the NGPA for sales of gas from the subject planned investment project or well for which there is no planned investment.

§ 271.1003 Special relief rate.

(a) *For a planned investment project.*

(1) Except for a small project as defined in § 271.1006(d)(1)(ii), the special relief rate for gas sold from a planned investment project shall be the rate under which it is predicted that the applicant will earn a 15 percent true yield on its expenditures incurred in the project. Such rate shall be determined using the discounted cash flow method and shall be effective over the life of the project. Taxes actually paid (other than State severance taxes as defined in § 271.1101(s) and Federal income taxes) may be added to the rate.

(2) The following standards shall apply in the determination of the special relief rate:

(i) Only those expenditures shall be considered which are prudently incurred and which are in line with comparable industry expenditures for such equipment, services and expenses for similar projects.

(ii) Investment and operating expenses shall not be considered if incurred:

(A) Prior to the date an application was filed under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77 of this chapter, provided that a notice has been filed under § 271.1004(d)(1);

(B) Prior to the date an application was accepted under § 271.1008(a)(3) in the case of applications to which subclause (A) of this clause does not apply.

(iii) The time between the commencement of investment and the earliest date of deliveries attributable to the project shall not exceed 1 year, absent reasonable justification for a longer period.

(iv) Recovery of Federal income tax shall be based on the marginal effective tax rate attributable to income from the project. The rate shall be the statutory rate applicable to additional taxable income of the investor after considering percentage depletion allowances and any applicable investment tax credits.

(v) Where operating expenses cannot be estimated over the estimated life of the project, operating expenses shall be determined for all years in the life of the project by estimating the operating expense for the first year in which deliveries are made under the special relief rate (exclusive of production, *ad valorem* and income taxes and any other adjustments allowed under Subpart K of this part) and escalating such expense at 7 percent compounded for each subsequent year;

(vi) Regulatory expense shall be determined by multiplying the net working interest production (in MMBtu's) by $.001;

(vii) Working capital allowance shall be determined by multiplying operating expenses (exclusive of production, *ad valorem* and income taxes and any other adjustments allowed under Subpart K of this part) by 0.125.

(b) *For a well for which there is no planned investment.*

(1) The special relief rate for gas sold from a well for which there is no planned investment shall be the rate under which it is predicted that the applicant will recover those out-of-pocket expenses which are reasonably assigned or allocated to gas production from the well. Taxes actually paid (other than State servance taxes as defined in § 271.1101(a)) may be added to the rate.

(2) The following shall apply in the determination of the special relief rate:

(i) The out-of-pocket expenses of the well shall be developed from the normal, recurring operating and maintenance expenses incurred and charged on the books and records of the producer for the production of hydrocarbons from the well and may include regulatory expense as provided in paragraph (a)(2)(vi) of this section.

(ii) Only those out-of-pocket expenses shall be considered which are to be prudently incurred and which are in line with comparable industry expenditures for such operation and maintenance for similar wells.

(iii) Where annual out-of-pocket expenses cannot be estimated over the estimated life of the project, out-of-pocket expenses shall be determined for all years in the life of the well by estimating the out-of-pocket expenses for the first year in which deliveries are made under the special relief rate (exclusive of production and *ad valorem* taxes and any other adjustments allowed under Subpart K of this part) and escalating such expense at 7 percent compounded for each subsequent year.

(iv) Out-of-pocket expenses shall not include capital investment, depreciation, depletion, amortization, return on investment (profit), amounts repaid on borrowed funds, Federal or State income taxes, any overhead which is not directly related and charged to the well and any other adjustments allowed under Subpart K of this part.

§ 271.1004 Application.

(a) *Scope of application.* A first seller shall make a separate application for each planned investment project or well for which there is no planned investment (as defined in § 271.1002) for which authority to charge and collect a special relief rate is sought.

(b) *Commencement of proceedings.*

(1) Except as provided in subparagraph (2) of this paragraph, a first seller shall commence a proceeding under this subpart by filing an initial application containing the applicable information required in § 271.1010(a) through (d).

(2) Applicants who have filed applications under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77 of this chapter before the effective date of this subpart shall be deemed to have commenced proceedings under this subpart, subject to the notice provisions of paragraph (d)(1) of this section.

(c) *Supplemental applications for certian planned investment projects.* In the case of the planned investment project which does not qualify as either a small project under § 271.1006(d)(1)(ii) or a project subject to the provisions of paragraph (d)(5) of this section, the first seller shall file a supplemental application containing the applicable information required in § 271.1010(e) within 60 days of completing the planned investment project.

(d) *Pending applications.* The following provisions shall apply to pending applications filed before the effective date of this subpart under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77 of this chapter:

(1) The application shall be deemed withdrawn for failure to go forward unless the applicant files within 30 days of the issuance of this subpart in final form a notice of intent to proceed with the application under the requirements of this subpart.

(2) Compliance with the notice requirement in subparagraph (1) of this paragraph shall:

(i) Authorize the applicant to collect retroactively, any special relief rate or rates approved under this subpart to the extent provided for in § 271.1009(c); and

(ii) Authorize the applicant to include expenditures in its application or applications made under this subpart to the extent provided for in § 271.1003(a)(2)(ii).

(3) Subsequent to or concurrent with the filing of the notice required in subparagraph (1) of this paragraph the applicant shall:

(i) Make a filing or filings conforming the application to the requirements in this subpart; or

(ii) File a statement that it believes the application conforms to the requirements of this subpart, that it does not intend to make a conforming filing and that it wishes to have the application reviewed under the requirements of this subpart, as filed.

(4) Except as provided in subparagrph (5) of this paragraph, an application shall not be considered as conforming to the requirements of this subpart unless:

(A) In the case of a planned investment project subject to the provisions of paragrph (c) of this section, which does not qualify as a small project under § 271.1006(d)(1)(ii), the application contains the applicable information required in § 271.1010(e);

(B) In all other cases, the application contains the applicable information required in § 271.1010 (a) through (d).

(5) In the case of a planned investment project (other than a small project) completed prior to the date of issuance of this subpart in final form, the application shall be deemed to conform to the requirements of this subpart if it contains the information required in § 271.1010(e).

(e) *Form of submission.* Each application, supplemental application or conforming application filed under this subpart shall be submitted in an original and 3 copies and shall be subscribed under oath by at least 1 working interest owner seeking special relief in the application.

(f) *Notice.*

(1) Each initial application, supplemental application or conforming application filed under this subpart shall

include a proposed notice which shall state the applicant's name, the date the application was filed under this subpart and the special relief rate requested. The proposed notice shall conform to the following form:

United States of America—Federal Energy Regulatory Commission

(Name of Applicant) ——————.

Notice of Application for Special Relief

On (date application was filed), (name of applicant) filed with the Federal Energy Regulatory Commission an application for special relief under Subpart J of Part 271 wherein (name of applicant) sought (special relief rate requested) for sales of natural gas to (name of purchaser).

The procedures applicable to the processing of this special relief application are found in 18 C.F.R. §§ 271.1001–271.1010.

Any person desiring to participate in this proceeding shall file a petition to intervene in accordance with the provisions of 18 CFR § 271.1005. Except as otherwise provided in § 271.1005, all petitions to intervene shall be filed within 15 days after publication of this notice in the **Federal Register.**

(2) The applicant shall serve a copy of any initial application, supplemental application or conforming application on each purchaser to whom sales of the natural gas for which the special relief rate is sought are made.

(3) Staff may require the applicant to provide additional service and shall cause notice of any initial application, supplemental application or conforming application to be published in the **Federal Register.**

(4) The certificate of service required under § 1.7 of this chapter shall indicate the names and addresses of all persons served.

§ 271.1005 Intervention.

(a) *Petition.* A petition to intervene under § 1.8 of this chapter shall be filed within 15 days after service of any application. If a person has not been served with an application, a petition to intervene under § 1.8 shall be filed within 15 days after publication of notice of the application in the **Federal Register.**

(b) *Action by Staff.* Staff shall act on all petitions filed under this section.

§ 271.1006 Review by Staff.

(a) *Procedures for certain initial applications.* In acting on an initial application filed under § 271.1004(b), or a filing made under § 271.1004(d)(3), for a planned investment project other than a small project as defined in paragraph (d)(1)(ii) of this section, the Staff may:

(1) Notify the applicant within 60 days of such filing of filing deficiencies in the application or request that the applicant provide additional information under paragraph (f)(2) of this section;

(2) Reject the application;

(i) For filing deficiencies if the apolicant has not submitted the information required under § 271.1004 within 30 days after issuance of a letter notifying the applicant of filing deficiencies in the application;

(ii) For failure to provide additional information as required in paragraph (f)(2) of this section within a reasonable time after it is requested;

(iii) Upon determining that the application fails on its face to meet all of the following criteria for special relief established in this subpart:

(A) The gas covered by the application must quality for special relief under §§ 271.1001 and 271.1002;

(B) There must be evidence of contractual authorization, as required under § 271.1002(b), to charge and collect the proposed special relief rate; and

(C) The proposed special relief rate must have been computed in accordance with the requirements of § 271.1003.

(3) Accept the application upon determining that:

(i) The applicant has complied fully with the filing requirements of § 271.1004 and has supplied all additional information requested under paragraph (f)(2) of this section; and

(ii) The application on its face meets all criteria for special relief specified in subparagraph (2)(iii) (A) through (C) of this paragraph.

(b) *Notice of Staff action.* Notice of all Staff actions specified in paragraphs (a) and (d) of this section, except issuances of deficiency letters or requests for additional information, shall be served upon all persons entitled to service

under § 271.1004(f) and all persons granted the right to intervene under § 271.1005.

(c) *Effect of acceptance of certain initial applications.* Except as provided in § 271.1003(a)(2)(ii)(A) for pending applications, acceptance of an initial application for a planned investment project, other than a small project as defined in paragraph (d)(1)(ii) of this section, shall authorize the applicant to include in its supplemental application filed under § 271.1004(c) those investments and expenses permitted under § 271.1003 which were made or incurred for the project subsequent to such acceptance, but shall not imply approval of any expenditures included in the application.

(d) *Procedures for other initial applications and for supplemental applications.*

(1) The procedures of this paragraph shall apply to the following:

(i) An initial filing made under § 271.1004 (b) or (d)(3) for a well for which there is no planned investment;

(ii) An initial filing made under § 271.1004 (b) or (d)(3) for a "small project," which is defined as a planned investment project which meets the following criteria at the time such filing is made:

(A) Planned development or production enhancement will result in additional revenues to the applicant of less than $60,000;

(B) The proposed investment in the project exceeds 25 percent of the estimated additional revenues to be generated by the projects; and

(C) The total rate proposed for the sale of gas is no more than 60 cents per MMBTU (exclusive of State severance taxes as defined in § 271.1101(a)).

(iii) A supplemental application filed under § 271.1004 (c) or (d)(5) for a planned investment project.

(2) In acting on any application described in subparagraph (1) of this paragraph, the Staff may:

(i) Notify the applicant within 60 days of such filing of filing deficiencies in the application or request that the applicant provide additional information under paragraph (f)(2) of this section;

(ii) Reject the application as provided in § 271.1008(a)(2);

(iii) Issue a Staff report which shall:

(A) Recommend approval of a specified special relief rate, and state the basis for recommending such rate and any dispute with factual assertions made by the applicant;

(B) Be served on all persons specified in paragraph (b) of this section.

(e) *Effect of issuing Staff report.* Issuance of a Staff report shall entitle all persons entitled to service of such report under paragraph (d) of this section to submit comments on the report and shall place the application before the Director of the Office of Pipeline and Producer Regulation (Director) for determination under § 271.1007.

(f) *Investigation and evaluation.*

(1) All filings made in connection with the application for special relief shall be considered in evaluating the application.

(2) The Staff may request additional information relevant to the application, and the applicant shall supply such information.

(3) The Staff may investigate the basis for any statement in the application, may conduct an audit, and may use in its evaluation any relevant fact obtained in such an investigation or audit.

(4) The Staff may solicit and accept submissions from intervenors or third persons relevant to the application.

(5) If the Staff obtaines information under subparagraph (3) or (4) of this paragraph and relies upon such information in making a decision under this section, the applicant shall be advised of such information and shall be given 5 days to respond to such information.

(6) The Staff may conduct a conference on the application in accordance with procedures it determines will most expeditiously further the purpose of such conference. A conference shall be convened only after actual notice of the time, place, and nature of the conference has been served upon all persons entitled to service under paragraph (b) of this section. All persons served may attend the conference, and the Staff may use in

its evaluation any relevant information obtained through such conference.

(g) *Definition of "Staff".* For purpose of this subpart, "Staff" means an employee of the Commission who has been appointed by the Director, but shall not include the Director.

§ 271.1007 Determination by the Director of the Office of Pipeline and Producer Regulation.

(a) *Determination.* The Director (or his designee) shall review the Staff report issued under § 271.1006(d)(2)(iii) and all comments filed under § 271.1006(e) and shall determine the special relief rate or recommend other appropriate action to the Commission on the application.

(b) *Finality.* Any determination of a special relief rate made by the Director under this section shall become final 30 days after notice is published in the **Federal Register** unless, during such period:

(1) A petition appealing the determination is filed under § 271.1008; or

(2) The Commission directs that the determination order be submitted to it for review under § 271.1008.

(c) *Notice of Director's determination.* Notice of the determination or recommendation made by the Director under this section shall be served upon the Commission and upon all persons specified in § 271.1006(b) and shall be published in the **Federal Register.**

§ 271.1008 Appeals to the Commission.

(a) *Petition for review.* A petition appealing any of the following actions shall be filed within 30 days of such action:

(1) A determination of a special relief rate made by the Director under § 271.1007;

(2) Staff acceptance or rejection under § 271.1006 of an initial or supplemental application;

(3) Staff rejection under § 271.1005 of a petition to intervene.

(b) *Who may petition.* A perspon may file a petition under paragraph (a) of this section if the person:

(1) Is adversely affected by the action appealed; and

(2) Except in the case of appeals regarding denials of intervention under § 271.1005, is specified in § 271.1006(b).

(c) *Contents of petition.* The petition shall include a copy of the order contested and a complete statement of the petitioner's factual or legal objections to the action taken.

(d) *On motion of the Commission.* The Commission may, on its own motion, direct that the action by Staff or the Director be submitted to it for review.

(e) *Action by the Commission.* Review of actions by the Staff and the Director shall be based on the record and shall provide such opportunity for additional submissions, including hearings, as the Commission deems appropriate.

§ 271.1009 Retroactive collection.

(a) *No planned investment.* Except as provided in paragraph (c) of this section, upon final approval of a special relief rate for a well for which there is no planned investment, the applicant may charge and collect that rate retroactively for sales of gas from the well beginning on the date the application was filed under § 271.1004(b).

(b) *Planned investment project.* Except as provided in paragraph (c) of this section, upon final approval of a special relief rate for a planned investment project, including a small project as defined in § 271.1006(d)(1)(ii), the applicant may charge and collect that rate retroactively for sales of gas from the project beginning on the date deliveries from the project were commenced.

(c) *Pending applications.* Upon final approval of a special relief rate for a pending application filed under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77, for which a notice was filed under § 271.1004(d)(1), the applicant may charge and collect that rate retroactively for sales of gas from the project:

(1) Beginning on the date 9 months following commencement of deliveries under the contract to which such special relief rate applies, if such application was filed under § 2.75 of this chapter;

(2) Beginning on the date such notice was filed under § 271.1004(d)(1), if such

application was filed under §§ 2.56a(g), 2.56b(h), 2.76, or 2.77 for a well for which there is no planned investment;

(3) Beginning on the later of the following, if such application was filed under §§ 2.56a(g), 2.56b(h), 2.76 or 2.77 for a planned investment project:

(i) The date notice was filed under § 271.1004(d)(1); or

(ii) The date on which deliveries from the project were commenced.

(d) *Verification by first purchaser.* In order to make retroactive collections contingent on commencement of deliveries, the applicant shall cause the first purchaser to submit to the Commission verification of such commencement.

§ 271.1010 Filing requirements.

(a) *For all planned investment projects.* Except as provided in paragraph (d) of this section for small projects, a filing made under § 271.1004 (b) or (d)(3) for a planned investment project shall include the following information:

(1) The name of the applicant;

(2) The applicant's principal place of business;

(3) The name and title, mailing address, and telephone number of the person responsible for the application;

(4) The working interest owners who are covered by the application and their respective percentages in the project and identification of any interest owners not covered by the application (including full details where the working interest varies for investment, operating expense, revenue, or any other reason);

(5) The royalty, overriding royalty, and non-operating interest owners associated with the project, according to category, including their respective percentages of the project and including a statement of any relationship to the project through ownership or employment or any other relationship;

(6) For each working interest owner covered by the application, the FERC certificate docket number and the FERC gas rate schedule number under which the gas has been or will be sold (applicable only to gas qualifying under section 104 or 106(a) of the NGPA);

(7) The name and address of the first purchaser;

(8) The maximum lawful price (in cents/MMBtu) each working interest owner covered by the application would be entitled to collect under the NGPA without reference to whether a contractual right exists to charge such price;

(9) The proposed special relief rate (in cents/MMBtu) computed in accordance with § 271.1003;

(10) An executed copy of each document to which the purchaser is a party which provides for the payment of the proposed special relief rate, as required in § 271.1002(b);

(11) The location of all facilities associated with the proposed project (including the State, county or parish, and field and well designations);

(12) The estimated recoverable reserves of gas (in Mcf's) and liquids (in bbls.) for the project, including a schedule of the project's anticipated annual production for each type of reserve (in Mcf's or bbls.);

(13) An estimate of future revenues, on a 100 percent working interest basis, by year, for the estimated remaining life of the project, which are to be generated by sales of liquids produced from the project or from any other project sources;

(14) An estimate of future operating expenses, on a 100 percent working interest basis, by year, for the estimated remaining life of the project involved;

(15) If Federal income tax expenses have been claimed under § 271.1003(a)(2)(iv), the calculation establishing the amount of taxes claimed;

(16) A detailed description of the project on a well-by-well or platform-by-platform basis and an estimate of the attendant costs segregated by major category, a proposed timetable for work and expenditures, and a discounted cash flow analysis showing the derivation of the special relief rate sought, consistent with § 271.1003; and

(17) At the option of the applicant, the data relating to the determination of reserves and gas deliverability required

under paragraph (e)(5) of this section for supplemental applications.

(b) *Additional information for certain planned investment projects.* A filing made under § 271.1004 (b) or (d)(3) for a planned investment project consisting of planned production enhancement work on a previously producing well shall include the following information in addition to that required in paragraph (a) of this section:

(1) An explanation of why the work is necessary;

(2) The price currently collected (in cents/MMBtu);

(3) The average unit Btu content (as determined in accordance with § 270.204) of the gas at the point of measurement for payment and the location of the point of delivery of the gas to the purchaser;

(4) Engineering and economic studies, equipment and service contracts and bids, and any other related documents necessary to substantiate the proposed expenditures and special relief rate;

(5) A schedule of operating expenses for the project on a 100 percent working interest basis detailed by cost item for the 2 most recent 12-month periods prior to the date of filing under § 271.1004(b) or (d)(1), including a description of the method or basis for assigning or allocating indirect costs or overheads to the lease and well; and

(6) A schedule of revenues and production volumes of gas (in Mcf's at 14.73 psia) and liquids (in bbls.) produced and sold at the lease level or credited back to the lease for the most recent 12-month period prior to the date of filing under § 271.1004(b) or (d)(1) on a 100 percent working interest basis, indicating whether the liquids are oil, lease condensate, or plant liquids, providing the current unit price and average Btu content of the liquids and reporting and describing any miscellaneous revenue received.

(c) *For wells for which there is no planned investment.* A filing made under § 271.1004(b) or (d)(3) for a well for which there is no planned investment shall include the information required under paragraphs (a)(1) through (14) and (b)(2) through (6) of this section as well as the following information pertaining to the determination of reserves and deliverability of the gas to which the application applies:

(1) A map delineating the exact acreage in the subject well area and showing the location of each completed, abandoned or proposed well and other facilities associated with the well;

(2) All electrical, acoustical, radioactive or other logs run on any well on the subject well acreage;

(3) All core analyses, conventional or sidewall, from any cores taken from any well on the subject well acreage;

(4) All tests, including open hole drill stem tests, wire line formation tests, initial production tests, single or multiple point backpressure tests, build-up or drawn-down tests and subsurface pressure surveys run on any well drilled on the subject well acreage;

(5) Tabulated production by year and month, separately by products, including oil, gas, condensate and water for all well completions on the subject well acreage;

(6) All well completion reports filed with the oil and gas regulatory authority having jurisdiction for wells drilled on the subject well acreage;

(7) All analyses made on separator or well stream gas or separator liquids produced from the subject well acreage;

(8) Tabulation by month and year of any plant liquids credited back to the leases in the subject well acreage from any processing plant;

(9) Tabulated reservoir parameters, by reservoir, for all reservoirs that are on the subject well acreage or that can be reasonably demonstrated to underlie the subject well acreage;

(10) Top of structure maps and isopach maps for all reservoirs that are actually productive or that have been proven productive by actual formation tests on the subject well acreage or that can be reasonably demonstrated to underlie the subject well acreage;

(11) The current average pipeline pressure of the purchaser at each point of sale for all gas sold from the subject well acreage; and

(12) In lieu of any of the information specified in subparagraphs (1) through (11) of this paragraph, citation to the application for certificate authority to sell the gas or the FERC Gas Rate Schedule in which such information is filed.

(d) *For small projects.* A filing made under § 271.1004(b) or (d)(3) for a project which qualifies as a small project under § 271.1008(d)(1)(ii) shall include the information required under paragraphs (a) (1) through (12), (b) (1) through (4) and (c) (1) through (12) of this section.

(e) *Supplemental applications.* A supplemental application for a planned investment project made under § 271.1004(c) or (d)(5) shall include:

(1) An estimate of the salvage value of the equipment involved in the project at the end of its useful life in the project on an item-by-item basis;

(2) A list, segregated by major category, of equipment and service contracts, invoices, and any other related documents necessary to substantiate the expenditures claimed in subparagraph (6) of this paragraph;

(3) The average unit Btu content (as determined in accordance with § 270.204) of the gas at the point of measurement for payment and the location of the point of delivery of the gas to the purchaser;

(4) The following data relating to the determination of reserves and deliverability of the gas to which the application applies:

(i) A map delineating the exact acreage in the project area and showing the location of each completed, abandoned or proposed well and other facilities associated with the project;

(ii) All electrical, acoustical, radioactive or other logs run on any well on the project acreage;

(iii) All core analyses, conventional or sidewall, from any cores taken from any well on the project acreage;

(iv) All tests, including open hole drill stem tests, wire line formation tests, initial production tests, single or multiple point backpressure tests, build-up or draw-down tests and subsurface pressure surveys run on any well drilled on the project acreage;

(v) Tabulated production, by year and month, separately by products, including oil, gas, condensate and water for all well completions on the project acreage;

(vi) All well completion reports filed with the oil and gas regulatory authority having jurisdiction for wells drilled on the project acreage;

(vii) All analyses made on separator or well stream gas or separator liquids produced from the project acreage;

(viii) Tabulation, by month and year, of any plant liquids credited back to the leases in the project acreage from any processing plant;

(ix) Tabulated reservoir parameters by reservoir for all reservoirs that are actually producing or that have proven productive by actual formation tests on the project acreage of that can be reasonably demonstrated to underlie the project acreage;

(x) Top of structure maps and isopach maps for all reservoirs that are actually productive or that have been proven productive by actual formation tests on the project acreage or that can be reasonably demonstrated to underlie the project acreage; and

(xi) The current average pipeline pressure of the purchaser at each point of sale for all gas sold from the project acreage;

(5) In lieu of the information specified in subparagraph (4) of this paragraph, citation to the application for certificate authority to sell the gas or the FERC Gas Rate Schedule in which such information is filed;

(6) A detailed description of the completed project along with the actual costs incurred, segregated by major category, and a discounted cash flow study reflecting actual costs computed in accordance with § 271.1003; and

(7) Any additional information which the applicant wishes to have considered.

¶ 32,034 Regulations Implementing the National Environmental Policy Act of 1969

44 F. R. 50052 (August 27, 1979).

[18 CFR Parts 2 and 3d]

[Docket No. RM79-69]

Regulations Implementing the National Environmental Policy Act of 1969

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission is proposing a new Part 3d of its regulations to replace §§ 2.80 through 2.82 as the basic procedural framework for collecting, evaluating, and disseminating environmental information about Commission actions or the proposed actions of applicants and jurisdictional entities. The regulations are drafted to reflect the policies and procedures of the NEPA regulations issued by the Council on Environmental Quality (40 CFR Parts 1500–1508), consistent with the Commission's independent regulatory responsibilities. The proposed rule lists those actions requiring an Environmental Assessment to determine if there is a major Federal action significantly affecting the quality of the human environment, thereby necessitating an Environmental Impact Statement (EIS). There are certain actions which automatically require an EIS and certain actions which are excluded from environmental reviews altogether, except in unusual circumstances.

Although many of the CEQ regulations are adopted by reference, the proposed rules provides applicants seeking Commission action or approval with a self-contained manual for compliance with NEPA.

DATE: Written comments by September 17, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, Reference Docket No. RM79-69

FOR FURTHER INFORMATION CONTACT:

James Hoecker, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8106, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-0422, or

Dr. Jack Heinemann, Advisor on Environmental Quality, Office of Regulatory Analysis, Federal Energy Regulatory Commission, Room 3347, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-6569.

Regulations Implementing the National Environmental Policy Act of 1969

Issued: August 20, 1979.

Notice is given that the Federal Energy Regulatory Commission (Commission) proposes to amend its regulations which govern the collection, evaluation, and dissemination of environmental information concern Commission actions, including actions on non-Federal projects within the Commission's jurisdiction, pursuant to the Department of Energy Organization Act, Natural Gas Act, Federal Power Act, the Public Utility Regulatory Policies Act, the Natural Gas Policy Act and the Interstate Commerce Act. The proposed regulations would replace and elaborate on existing Commission regulations under the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321–4347. The proposed regulations reflect the policies and essential procedures of the NEPA regulations promulgated by the Council on Environmental Quality, 40 CFR Parts 1500–1508.

Background

Section 102(2)(C) of NEPA provides in part that all Federal agencies shall

> Include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on:
> (i) The environmental impact of the proposed action;
> (ii) Any adverse environmental effects which cannot be avoided should the proposal be implemented;
> (iii) Alternatives to the proposed action;
> (iv) The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
> (v) Any irreversible and irretrievable commitment of resources which would be involved in the proposed action should it be implemented.

On December 18, 1972, the Federal Power Commission, predecessor to the Federal Energy Regulatory Commission, issued Order No. 415–C to comply with the NEPA mandate that Federal agencies preserve the natural, cultural, historic, aesthetic, and biologic environments by requiring calculation and reporting of the probable environmental impact of Federal actions and programs and by prescribing means for preventing or mitigating environmental damage. Since the issuance of Order No. 415–C, §§ 2.80 through 2.82, and appendices that describe what applicants should include in an Environmental Report, have guided Commission review of environmentally related actions undertaken by permittees, licensees, and applicants within Commission jurisdiction.

On November 29, 1978, the Council on Environmental Quality (CEQ) published in the **Federal Register** its regulations implementing NEPA. The CEQ regulations establish processes which enable Federal executive agencies to work together in researching and solving environmental problems and provide for uniform methods of writing environmental impact statements and assessments, receiving comments, developing records of decision, and handling information. (40 CFR Parts 1500–1508) Executive agencies are bound by the CEQ regulations, and have supplemented them with interpretive guidelines. (See *e.g.*, proposed Department of Energy guidelines, 44 FR 42136, July 18, 1979). The Commission has determined not to adopt the CEQ regulations in their entirety. Rather, the Commission proposes to adopt much of the CEQ regulations with accompanying elaborative provisions which are specifically tailored to the Commission's particular procedures, functions, and responsibilities as an independent collegial body that regulates the activities of non-Federal entities.

Although the Commission, as an independent regulatory agency, is not bound by the CEQ regulations, it concurs in the policies reflected in the CEQ regulations. In the interests of uniformity, the Commission has determined to structure its own regulations as closely as practicable to the essential procedures reflected in the CEQ regulations, while ensuring that its regulations are consistent with its independent regulatory duties and responsibilities.

The Commission is also proposing environmental regulations for the management of floodplains and the protection of wetlands which are directly related to the NEPA processes proposed here. See Docket No. RM79–70.

The regulations proposed in this docket were developed in consultation with CEQ.

The Proposed Regulation

The rulemaking revokes the existing NEPA regulations and retains Appendices A and B, which specify the components of an Environmental Report for certain projects under the Federal Power Act and Natural Gas Act, respectively. Those appendices are transferred to new Part 3d, the NEPA regulations. The appendices are amended to eliminate the "abbreviated application" whereby an applicant was allowed to show that a project has no significant environmental impact and thus avoid filing a report. Section 3d.12

would require Environmental Reports without exception for certain types of actions or projects.

Appendix A will serve an increasingly limited role as the Commission revises its water power project licensing procedures to vary the Environmental Report requirements according to the type of project application. Only applications for major unconstructed water power projects and certain interconnection and transmission facilities will utilize Appendix A after the proposal in Docket No. RM79–36 is issued as a final rule.[1] New Appendix C is a flow chart showing the conceptual framework of the NEPA process for evaluating environmental issues.

Subpart A of Part 3d expresses the Commission's general approach to implementing NEPA and its goals and adopts most of the CEQ regulations for early and efficient review of environmental issues, public notice and participation, scoping, and inter-agency cooperation. The Commission proposes to adopt by reference certain parts of the CEQ regulations and to adopt others with revisions to accommodate its particular procedures and functions. Those sections to be adopted by reference wholly or in part (40 CFR Parts 1501, 1502, 1503, 1505 and 1508) should be read in conjunction with the proposals in this docket. They contain the general concepts, processes, and definitions used in the evaluation of environmental information.

Certain portions of the CEQ regulations may be inconsistent with the Commission's primary jurisdictional statutes.[2] Part 1504 of the CEQ regulations establishes a procedure whereby an agency's environmental impact statements and judgments about the acceptability of an action's impact may become subject to CEQ review outside the particular agency's NEPA processes. For proceedings under the Commission's primary jurisdictional statutes, however, any disputed issues must be decided by the Commission, on the full record before it, subject to statutory judicial review. Resolution of disputed issues by CEQ in such proceedings would be inconsistent with the statutory regulatory schemes. The Commission will enter any CEQ opinion on an environmental issue in the record of the relevant proceedings, however. Such an opinion will be considered advisory unless CEQ is a party to the proceeding. Part 1504 is appropriate for use by the Commission in those instances where environmental disagreements arise in a context other than regulatory decisionmaking under the Commission's primary jurisdictional statutes. Section 3d.14(c) of the proposed regulations reflects the limitations on the Commission's participation in Part 1504 process.

The Commission adopts the procedures established by CEQ under 40 CFR 1501.5 for determining lead agency designations if agencies disagree. It does so in the interest of interagency cooperation and with the expectation that such procedures will not unnecessarily delay or infringe on the Commission's independent regulatory decisionmaking.

Other deviations from the CEQ regulations concern form more than substance. Section 3d.21 proposes a slightly different format for Environmental Impact Statements than that in the CEQ model, because the Commission has determined from prior experience that the § 3d.21 format provides a more useful analytical focus for proposed actions under the Commission's particular regulatory responsibilities.

Parts 1500 and 1507 of the CEQ regulations simply provide statements of CEQ's purposes, policies, and mandate in issuing its regulations and instructions to agencies on implementation of CEQ's regulations.

[1] In Docket No. RM78–9, 43 FR 40215 (September 11, 1978), the Commission established a separate Environmental Report for all minor water power projects (less than 2,000 horsepower of installed capactiy). Other rulemakings are establishing separate Environmental Report requirements for particular kinds of water power projects. Docket No. RM79–36 concerns major projects at existing dams.

[2] See 40 CFR 1500.3, 1507.3(b).

These provisions are therefore not necessary for inclusion in the Commission's regulations.

Part 1506 has been largely revised as § 3d.13 of these proposed regulations, with modifications to those provisions of the CEQ regulations which might infringe upon the Commission's timely discharge of its regulatory functions. In addition, Part 1506 contains a number of provisions sufficiently important to applicants and other participants in the Commission's regulatory proceedings to warrant placing them in the Commission's regulations. The proposed regulations should provide a clear, concise, and self-contained manual on those matters for participants in the Commission's proceedings.

Subpart B of the proposed regulations contains the basic NEPA procedures and substantive requirements to be used by the Commission. Section 3d.10 sets forth the role that environmental documents will play in the Commission's decisions whether to approve or disapprove projects or programs, issue licenses or permits, or propose legislation. The Commission will routinely require that Environmental Assessments be prepared for certain proposals or applications to determine if the proposed action will be a major Federal action significantly affecting the quality of the human environment. Such an action would necessitate an Environmental Impact Statement for Commission and public consideration. (Section 3d.10(b)). Certain other proposed actions that almost always trigger the writing of an Environmental Impact Statement are set forth in § 3d.10(c). The procedures for intervenors to follow in Commission proceedings insofar as environmental concerns are at issue, is found in § 3d.10(e).

A variety of actions, some taken on proposals by applicants and others of an internal or administrative nature, are excluded as a class from the requirements of this part. The Commission believes that no genuine environmental interest is served by extensively reviewing certain types of actions or proposals for environmental impact. Almost by definition, the impact of most of the actions listed are extremely remote, incalculable, or non-existent. Many of the actions have impacts that are exclusively social and economic. The CEQ regulations do not contemplate environmental review of such actions. However, the Commission recognizes the possibility that unusual circumstances may create the need for examination of the environmental consequences of any of these excluded actions. It therefore proposes to evaluate the environmental impact of such normally excluded actions if the staff, an applicant, or an intervenor shows that circumstances warrant such evaluation. (§ 3d.11(b))

While the proposed rulemaking is intended to comprehend all Commission actions and applicant proposals within the three classes of actions in the NEPA process (*i.e.*, actions requiring an EA or an EIS, or actions usually excluded from environmental review), these classes may be subject to later expansion or reorganization. As the Commission is given new action by Congress, or recognizes that a particular responsibility requires or does not require environmental evaluation,[3] the regulation would be amended accordingly.

Section 3d.12 provides guidance to applicants about the NEPA process and indicates the general responsibilies of staff during the process. Paragraph (c) directs applicants to specific requirements for preparing Environmental Reports according to the type of proposed action.

Section 3d.13 parallels the CEQ regulations at 40 CFR Part 1506. This section explains limitations against

[3] For example, in issuing a final rule establishing transportation certification for natural gas for displacement of fuel oil (Order No. 30, issued May 17, 1979, Docket No. RM79-34), the Commission assessed potential environmental impacts of this kind of action and found no significant impact. This finding is now reflected in proposed § 3d.11(a)(23).

prejudicial actions during the NEPA processes, cooperation with State and local agencies, the use of an EIS written by another Federal agency, public involvement in decisions affecting the environment, the NEPA process in relation to legislative proposals, cooperation with the Environmental Protection Agency, and the timing of Commission action in relation to public notice, the Adminstrative Procedure Act, and emergency circumnstances.

Section 3d.14 reflect the Commission's intention that all issues, including environmental issues, be resolved within Commission proceedings exclusively when a proposed action is within the Commission's independent regulatory responsibility, subject to court review as provided in its jurisdictional statutes. In those instances, any recommendation by CEQ on a referral to it under Part 1504 of the CEQ regulations would be entered in the record as advisory only, unless CEQ is a party to the proceeding. In other instances, such as when acting as a cooperating agency, the Commission proposes to allow or initiate referral of environmental disputes to CEQ for resolution. The environmental consequences of any action which is subject to proceedings under the Federal Power Act, Natural Gas Act, or other primary jurisdictional statutes may be debated by intervenors, public or private, as participants in Commission proceedings. Under proposed § 3d.15, coordination of the Commission's NEPA activities relating to NEPA and cooperation with CEQ and other agencies would be the responsibility of the Commission's Advisor on Environmental Quality.

Subpart C proposes specific requirements for the preparation and content of Environmental Assessments (§ 3d.20) and Environmental Impact Statements (§ 3d.21), the fundamental documents in the NEPA process.

Comment Procedure

Interested persons are invited to submit written views, comments, or suggestions in writing concerning all or part of the regulations proposed in this notice. An original and 14 copies of any comment should be filed with the Secretary of the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Comments must be received by September 17, 1979, and should reference Docket No. RM79-69. Written submissions will be available for public inspection at the Ofice of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours. The Commission will consider all written submittals before acting on the proposed regulations.

(Department of Energy Organization Act, 42 U.S.C. 7101–7352; Executive Order No. 12009, 42 FR 46267; National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321–4347.)

In consideration of the foregoing, the Commission proposes to amend Part 2 and add Part 3d in Chapter I, Title 18, Code of Federal Regualtions as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 2—GENERAL POLICY AND INTERPRETATIONS

§ 2.80, 2.81, 2.82 [Revoked]

Appendices A and B [Amended]

1. Part 2, Subchapter A, Chapter 1 of Title 18, Code of Federal Regulations, is amended by revoking §§ 2.80, 2.81, and 2.82 and by transferring Appendices A and B to Part 3d. Appendices A and B are amended by deleting the first paragraph of numbered guideline (8), deleting from numbered guideline (2) the words "the Commission's Order No. 415C (issued December 18, 1972) amending §§ 2.80–2.82," and inserting in lieu thereof the words "Part 3d," and deleting from numbered guideline (3) in Appendix A the term "§ 2.81(a)" and from numbered guideline (3) in Appendix B the term "§ 2.82(a)", inserting in lieu thereof the term "§ 3d.12" in both places. The title of Appendix A is revised to read:

"Guidelines for the Preparation of Environmental Reports for Major Unconstructed Water Power Projects and Other Applications under Part I of the Federal Power Act, as specified in Section 3d.12."

2. Subchapter A, Chapter 1 of Title 18, Code of Federal Regulations, is amended by adding a new Part 3d and an Appendix C to read as follows:

PART 3D—REGULATIONS IMPLEMENTING THE NATIONAL ENVIRONMENTAL POLICY ACT

Subpart A—General

Sec.
3d.1 Purpose.
3d.2 Council on Environmental Quality NEPA regulations.
3d.3 Definitions.

Subpart B—Procedure

3d.10 Environmental documents and FERC decisionmaking.
3d.11 FERC categorical exclusions.
3d.12 Applicant and staff responsibilities and environmental reports.
3d.13 Other requirements of NEPA.
3d.14 Interagency resolution of disagreements on environmental matters.
3d.15 Coordination of NEPA activities.

Subpart C—Environmental Documents

3d.20 Environmental assessment.
3d.21 Environmental impact statement.

Appendix A—Guidelines for the Preparation of Environmental Reports for Major Unconstructed Water Power Projects and Other Applications Under Part I of the Federal Power Act as specified in Section 3d.12.

Appendix B—Guidelines for the Preparation of Applicants' Environmental Reports for Applications under Section 7(c) of the Natural Gas Act.

Appendix C—FERC Decisionmaking Process under NEPA.

Authority: National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321–4347, and the Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352.

Subpart A—General

§ 3d.1 Purpose and applicability.

(a) This part sets forth the procedures by which the Federal Energy Regulatory Commission (Commission) assesses the environmental consequences of any Commission action not categorically excluded from this part by § 3d.11, particularly the consequences of Commission authorization or licensing of projects for the production, transport, or sale of gas, oil, or electricity within the Commission's jurisdication. The regulations implement the National Environmental Policy Act of 1969 (NEPA) and adopt or reflect the policies set forth in the NEPA regulations of the Council on Environmental quality (CEQ), to the extent that those regulations are consistent with the Commission's reponsibilities and practices. The regulations apply to environmental documents and review processes initiated before the effective date only to the extent practicable.

(b) This part provides the means for early identification and assessment of environmental issues and problems, thereby assisting the Commission in protecting the human environment in the course of its decisionmaking. The Commission encourages public involvement in decisions affecting the environment and, to that end, requires the presentation of genuine environmental issues and alternatives and the formulation of clear and concise environmental documents.

§ 3d. 2 Council on Environmental Quality NEPA Regulations.

The Commission adopts the following parts of the Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act issued by CEQ as part of Title 40 of the Code of Federal Regulations, except of modified by this part: Part 1501, Part 1502 (except §§ 1502.10–.18, whch are replaced by § 3d.21(c) of this part), Part 1503, Part 1505, and Part 1508 (which is supplemented by the definitions in § 3d.3 of this part).

§ 3d. 3 Definitions.

The terms used in this part have the meanings set forth in 40 CFR Part 1508 and in this section. For the purposes of this part—

(1) "Commission" means the Federal Energy Regulatory Commission its staff, or organizational units.

(2) "Environmental Report" or "ER" means a document submitted to the Commission by an applicant as that part of an application for authorization of a proposed action identifying the environmental impact of the action and alternatives to the action.

(3) "Secretary" means the Secretary of the Commission.

Subpart B—Procedures

§ 3d.10 Environmental documents and FERC decisionmaking.

(a) *Environmental considerations and decisionmaking.* (1) It will be the policy of the Commission to adopt and adhere to the objectives and aims of NEPA in all Commission actions, including its actions under the Department of Energy Organization Act, the Federal Power Act, the Natural Gas Act, the Interstate Commerce Act, the Natural Gas Policy Act, the Power Plant and Industrial Fuel Use Act, the Alaska Natural Gas Transportation Act and the Public Utility Regulatory Policies Act. The Commission will include a detailed environmental Impact Statement in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment.

(2) Major docketed electric, gas, and oil items, including actions that are new or continuing on the effective date of this part, proposed actions or programs, or expansion or revisions of actions or programs requiring Commission authorization are reviewed in status reports updated periodically. If Commission actions or programs are likely to have a significant impact on the human environment, environmental considerations will be addressed at appropriate major decision points. The flow chart in Appendix C generally illustrates decision points for compliance with NEPA in Commission decisionmaking.

(3) Relevant environmental documents [40 CFR § 1508.10], comments, and responses will be part of the record of decision [40 CFR § 1505.2] in rulemaking and adjudicatory proceedings.

(4) The Environmental Report (ER), Environmental Assessment (EA), Environmental Impact Statement (EIS), comments, and responses [40 CFR Part 1503] will accompany the proposal through existing agency review processes so that all levels of the Commission may use them in making decisions.

(5) The alternatives the Commission considers with respect to major Federal actions significantly affecting the quality of the human environment will encompass the range of alternatives described in the relevant environmental documents. The Commission will consider the alternatives described in the EIS.

(b) *Actions that require an EA.* For proposals identified in this paragraph and not normally requiring an EIS under paragraph (c) of this section, the Commission will prepare an EA under § 3d.20 as part of the record of decision on the environmental effects of the proposed action. An EA will ascertain whether the proposed Action is a major Federal Action significantly affecting the quality of the human environment under section 102(2)(c) of NEPA. Proposals that will normally require an EA are:

(1) Construction or abandonment of compression, processing, interconnecting, pipeline, and metering facilities;

(2) Filing for a certification of sale, exchange, or transportation of gas;

(3) Natural gas abandonment or reduction of service;

(4) Conversion of existing depleted oil or gas fields to underground storage fields;

(5) Natural gas curtailment plans;

(6) Licensing of minor water power projects (not more than 2000 horsepower, or 1.5 MW, of installed capacity);

(7) Licensing of major water power projects (more than 2000 horsepower or 1.5 MW)—existing dams (see § 4.50);

(8) Surrender of water power project licenses and changes in licensed water power project facilities, operation, or boundaries;

(9) Exemptions for small conduit hydroelectric facilities;

(10) Licenses for transmission lines only;

(11) Electrical interconnections and wheeling under §§ 202(b), 210, 211, and 212 of the Federal Power Act, that would entail substantial new construction; and

(12) Regulations or proposals for legislation not excluded under § 3d.11 that may have significant environmental effects [40 CFR § 1508.8].

(c) *Actions that require an EIS.* The Commission will prepare an EIS pursuant to § 3d.21 of this part for the following types of proposals, unless the proposed action is not a major Federal action significantly affecting the quality of the human environment [40 CFR Part 1508]:

(1) Projects for liquefied natural gas import/export facilities;

(2) Major new onshore/offshore natural gas pipeline projects; and

(3) Construction of new major water power projects, that is, projects other than minor projects or major projects—existing dams.

(d) *Consultation with CEQ.* The Commission may consult with the CEQ under § 3d.14 in determining the need for an EIS.

(e) *Intervention and hearing.* (1) In addition to the opportunity to petition to intervene in response to a notice of an application, any person also may file a petition to intervene in Commission proceedings on the basis of a staff draft EIS within the time period for submitting comments prescribed in the notice of availability of the draft EIS. Any intervenor that takes a position on environmental matters must file timely comments with the Secretary containing an analysis of its environmental position and specifying any differences with the position of staff upon which the intervenor wishes to be heard. Nothing in this section precludes an intervenor from filing a separate ER.

(2) In the case of an EIS set for hearing, the applicant, the staff, and all intervenors that take a position on environmental matters must offer evidence for the record in support of their environmental positions. The applicant and all such intervenors must specify any differences with the position of the staff and other relevant factors.

(3) In the case of an EIS set for hearing, the initial and reply briefs filed by the applicant, the staff, and all intervenors taking a position on environmental matters must specifically analyze and evaluate the evidence in the light of the environmental criteria set forth in § 3d.21(b).

(4) The initial decision of the Presiding Administrative Law Judge in such cases, and the final order of the Commission dealing with the application on the merits in all cases, will include an evaluation of the environmental factors described in the EIS and the views and comments expressed in conjunction therewith by the applicant and those making formal comment pursuant to the provisions of this part.

§ 3d.11 Categorical exclusions.

(a) *General rule.* There are certain categories of actions that normally are not major Federal actions significantly affecting the quality of the human environment. Such actions are categorically excluded from the requirements of this part, except as provided in paragraph (b). Those programs, actions, and procedures which are categorically excluded from application of this part are:

(1) Procedural, ministerial, or internal administrative and management actions, programs, or decisions, including procurement, contracting, personnel actions, correction or clarification of filings or orders, and acceptance and rejection of filings;

(2) Reports or recommendations on legislation not initiated by the Commission;

(3) Compliance and review actions, including investigations (jurisdictional or otherwise), conferences, hearings, notices of probable violation, show cause orders, review of denials of adjustment requests, and of contested remedial orders;

(4) Proposals for legislative and promulgation of rules and regulations which are clarifying, corrective, or procedural, or which do not

substantially change the effect of legislation or regulations being amended;

(5) Information gathering, analysis, and dissemination;

(6) Conceptual or feasibility studies;

(7) Actions concerning the reservation and classification of United States lands as water power sites and other actions under section 24 of the Federal Power Act;

(8) Transfers of water power project licenses;

(9) Withdrawals of applications for certificates or for water power project preliminary permits or licenses;

(10) Setting of annual charges or headwaters benefits charges for water power projects;

(11) Approval for water power projects of "as built" or revised drawings or exhibits that propose no changes of consequence to project works or operations or that reflect changes that have previously been approved or required by the Commission;

(12) Review or approval of study proposals required by a license or preliminary permit for a water power project;

(13) Review of filings made in compliance with the requirements of a preliminary permit or license order or article for a water power project;

(14) Issuance of preliminary permits for water power projects;

(15) Water resource appraisal studies;

(16) Review of electric rate filings submitted by public utilities and confirmation and approval of rate filings submitted by Federal power marketing agencies;

(17) Review and approval of actions under the Federal Power Act relating to issuance and purchase of securities, acquisition or disposition of property, merger, interlocking directorates, jurisdictional determinations, and accounting orders;

(18) Budget-type facilities applications filed under § 157.7(b), (c), (d) and (g) of this chapter, such as gas-purchase facilities or field gas compression facilities;

(19) Producers' applications for the sale of gas filed under §§ 157.23–.29 of this chapter;

(20) Approval of taps, meters, and regulating facilities located within an existing right-of-way where the land use of the vicinity has not changed since the original facilities were installed.

(21) Review of natural gas rate filings, except curtailment plans;

(22) Review of oil pipeline rate filings; and

(23) Plans for displacement of fuel oil by natural gas.

(b) *Unusual circumstances.* If there are unusual circumstances in which a categorically excluded action might be a major Federal action significantly affecting the quality of the human environment, the Commission staff will prepare an EA or EIS.

§ 3d.12 Applicant and staff responsibilities and environmental reports.

(a) *Applicant responsibilities.* (1) Any applicant seeking authorization from the Commission for any proposal identified in § 3d.10(b) and (c) must submit an ER with the proposal as prescribed in paragraph (c) of this section. In particular instances, the Commission may require applicants to submit environmental information required to comply with these regulations on proposals not identified as requiring an ER.

(2) An applicant seeking Commission authorization must also:

(i) Carry out a good-faith effort to provide all necessary or relevant information to the Commission;

(ii) Conduct any studies that the Commission staff considers necessary or relevant to determine the impact of the proposal on the human environment and natural resources;

(iii) Consult with appropriate Federal, regional, state, and local agencies throughout the planning stages of the proposed action, to assure that all potential environmental impacts are identified;

(iv) Submit applications for all Federal and state approvals as early as possible tin the planning process;

(v) Notify the Commission staff of all other Federal actions required for completion of the proposed action so that the staff may coordinate with other interested Federal agencies.

(vi) Before completion of the EA/EIS process and issuance of a Commission decision, the applicant may not take any steps toward completion of a propose action that may cause significant environmental impact, or that may foreclose alternatives available to the applicant or the Commission.

(b) *Staff responsibilities.* (1) The Commission staff will be available to provide informal guidance to any prospective applicant regarding the proper scope and depth of analysis in an ER. Such staff guidance will not bar any subsequent determination by the staff, an Administrative Law Judge, or the Commissioners that additional data or analysis must be submitted under this rule.

(2) The staff will review the methodologies employed by the applicant in its ER and independently evaluate the environmental impacts of the proposed action and all alternatives. Using the ER and other pertinent data and analyses, the staff will independently determine whether a proposed action requires EA or an EIS. Any information or analysis in the ER that is used by staff or relied on for preparation of an EA or EIS will be verified and independently evaluated.

(c) *Content of an ER for specific proposals.* (1) *Water power projects.* (i) Any application under Part I of the Federal Power Act for a license for a major water power project (more than 2,000 horsepower or 1.5 Mw of capacity) other than a major project—existing dam (see § 4.50 of this chapter) must include an ER which conforms to the requirements of Appendix A of this part and the requirements of § 4.41 [Exhibit W].

(ii) Any application under Part I of the Federal Power Act for a license for a major project—existing dam, as defined in § 4.50(b), must include an ER which conforms to the requirements of § 4.51(f) [Exhibit E].

(iii) Any application for the surrender or for the amendment of a license that proposes a change in the existing state of project works or project operation that would significantly increase the normal maximum surface area or normal maximum surface elevation of an existing impoundment, create a new impoundment, or significantly affect the quality of the human environment, must include an ER that conforms to the requirements of Appendix A of this part. Any application for surrender or amendment of a license that proposes a change in the existing state of project works or project operation that would not have any of the effects described in this clause must include an ER which conforms to the requirements of § 4.51(f) [Exhibit E]. A propsective applicant may seek advice from the Commission staff concerning whether any proposed change in the existing state of project works or project operation would result in a significant increase in the normal maximum surface area or normal maximum surface elevation of an existing impoundment, or could significantly affect the quality of the human environment, subject to § 3d.12(b)(1).

(iv) An application for a minor water power project (not more than 2,000 horsepower, or 1.5 MW, of installed capacity) must include an ER which conforms to the requirements of § 131.8 of this chapter.

(v) An application for exemption of a small conduit hydroelectric facility from all or part of Part I of the Federal Power Act must include the Environmental Report specified in § 4.66(b)(5) of this chapter.

(vi) An application either under § 4.70 of this chapter for a license for transmission line only or under §§ 202(b), 210, 211, or 212 of the Federal Power Act for electrical connections or wheeling which would entail substantial new construction must include an ER which conforms to the requirements of Appendix A of this part, to the extent that those requirements are applicable to the transmission lines or other electrical facilities proposed.

(2) *Gas projects.* Any application filed under the Natural Gas Act for a proposal identified in § 3d.10 (b) or (c) must include an ER that contains the environmental information and analysis specified in Appendix B of this part.

(3) *Format of an ER.* (i) Appendices A and B of this part are intended to provide specifications for the content of an ER and not to impose rigid requirements for format.

(ii) The level of detail in an ER must be commensurate with the complexity and expected significance of the environmental impacts of the proposed action. An ER must be a substantially self-supporting public document in which the data are accurate and complete. Data pertinent to the assessment of environmental impacts must be included in the text in a form that may be readily understood by the Commission staff and the public. For additional guidance in preparing an ER, see §§ 2.13, 2.14, 2.69, and 2.78 of this chapter.

§ 3d.13 Other requirements of NEPA.

(a) *Limitations on actions.* Except as provided in paragraph (b) of this section, the Commission will not undertake, or permit to be undertaken, any step toward completion of a proposed action which would have an adverse environmental impact or restrict the choice of reasonable alternatives until the appropriate EA/EIS process has been completed and a decision issued by the Commission. The Commission will take action to ensure that the objectives and procedures of NEPA are achieved when the Commission becomes aware that an applicant or jurisdictional entity may take or has taken such a step.

(b) While work on a required EIS for a program described in 40 CFR § 1508.18(b)(3) is not covered by an existing program EIS, the Commission will not undertake, or permit to be undertaken, any action that may significantly affect the quality of the human environment unless the action:

(1) Is justified independently of the program;

(2) Is itself accompanied by an adequate EIS; and

(3) Will not prejudice the ultimate action on the program.

(c) *Cooperation with state and local agencies.* (1) The Commission will cooperate with state and local agencies to the fullest extent possible, consistent with its primary jurisdictional statutes, to reduce duplication between NEPA and state or local requirements. Such cooperation may include joint planning, joint environmental research and study, and the conduct of joint hearings, subject to the requirements of Part 1 of this chapter.

(2) The Commission may share with state and local agencies its responsibility to formulate environmental documents.

(3) The Commission will reconcile NEPA with state law and local ordinances to the fullest extent possible, consistent with its primary jurisdictional statutes. An EIS will discuss any inconsistencies between a proposed action and any approved state or local plan or law and will discuss how the inconsistency would be resolved.

(d) *Adoption of the EIS of a Federal agency.* (1) The Commission may adopt a draft or final EIS prepared by another Federal agency or portion of either if the EIS, or adopted portion of it, meets the standards for an adequate EIS under this part.

(2) If the actions that are covered by the adopted EIS are substantially similar to the proposed action, the Commission, in adopting the EIS of another Federal agency, will not recirculate it except as a final EIS. Otherwise the Commission will treat the EIS as a draft and recirculate it (except as provided in subparagraph (4)).

(3) The Commission, as a cooperating agency [40 CFR 1501.6], may adopt without recirculation the EIS of a lead agency when, after an independent review of the EIS, the Commission concludes that its comments and suggestions have been satisfied.

(4) The Commission will specify if any of the following circumstances exist

with respect to adopting all or part of an EIS of another Federal agency:

(i) The EIS is not final within the agency that prepared it;

(ii) The action that the EIS assesses is the subject of a referral under 40 CFR Part 1504; or

(iii) The adequacy of the EIS is the subject of a judicial action that is not final.

(e) *Combining documents.* Any environmental document that is prepared to comply with NEPA may be combined with any other Commission documents to reduce duplication and paperwork.

(f) *Public involvement.* (1) *Notice.* The Commission will provide public notice of NEPA-related hearings, public meetings, and the availability of environmental documents to inform those persons and agencies who may be interested or affected.

(i) In the case of an action with effects of national concern, notice will include publication in the Federal Register and notice by mail to national organizations reasonably expected to be interested in the matter.

(ii) In the case of an action with effects primarily of local concern, the notice may include:

(A) Notice to state and area-wide clearinghouses;

(B) Notice to Indian tribes when effects may occur on reservations;

(C) Use of the affected state's public notice procedures for comparable actions;

(D) Publication in local newspapers of general circulation; or

(E) Notice through other local media.

(2) *Hearings or meetings.* (i) The Commission will hold or sponsor hearings or public meetings if required by statute or if the Commission otherwise determines appropriate. Criteria that will be considered in determining whether to hold a hearing or public meeting include:

(A) Substantial environmental controversy concerning the proposed action or substantial interest in holding the hearing or meeting;

(B) A request for a hearing or meeting by another agency with jurisdiction over the action, supported by reasons why a hearing or meeting will be helpful.

(ii) If a draft EIS is to be considered at a hearing or public meeting, the Commission will normally make the EIS available to the public at least 15 days in advance, unless the purpose of the hearing or meeting is to provide information for the draft EIS.

(3) *Information.* The Commission will make information or status reports on an EIS and other elements of the NEPA process available to interested persons through the Commission's Advisor on Environmental Quality, Office of Regulatory Analysis.

(4) *Documents.* The Commission will make the EIS, the comments received, and any underlying documents available to the public from the Commission's Office of Public Information. Materials made available will include interagency memoranda to the extent that those memoranda transmit comments of Federal agencies on the environmental impact of the proposed action. Materials will be provided to the public without charge to the extent practicable, or at a fee that is not more than the actual cost of reproducing copies. A copy of each EIS will be available for inspection at the Commission's regional office for the region in which the proposed action would occur.

(g) *Proposals for legislation.* (1) The NEPA process for proposals for legislation [40 CFR 1508.17] significantly affecting the quality of the human environment will be integrated with the legislative process of the Congress. An EIS will be part of the formal transmittal of a legislative proposal to Congress. It may be transmitted to Congress up to 30 days later in order to allow time for completion of an accurate EIS which can serve as the basis for public and Congressional debate. The EIS will be available in time for Congressional hearings and deliberations.

(2) Preparation of an EIS for a legislative proposal will conform to the requirements of this part, except that:

(i) There need not be a scoping process [40 CFR § 1508.25];

(ii) When any of the following conditions exist, both the draft and final EIS on the legislative proposal will be prepared and circulated:

(A) A Congressional committee with jurisdiction over the proposal has a rule requiring both a draft and a final EIS;

(B) The proposal results from a study process required by statute; or

(C) Legislative approval is sought for Federal or Federally assisted construction or other projects that the Commission recommends be located at specific geographic locations.

(h) *Filing with the Environmental Protection Agency.* An EIS prepared by the Commission staff, with comments and responses, will be filed with the Environmental Protection Agency (EPA) at the time it is transmitted to commenting agencies and made available to the public.

(i) *Timing of Commission action.* (1) Under 40 CFR 1506.10, the EPA is required to publish a notice of availability and distribution of an EIS in the **Federal Register.** If the EPA fails to publish such notice within 15 days of the filing of the EIS under paragraph (h) of this section, the Commission will publish such notice. The minimum time periods set forth in this section will be calculated from the date of publication of this notice.

(2) No decision on the proposed action will be made by the Commission until the later of the following dates:

(i) Ninety (90) days after publication of the notice of a draft EIS under this paragraph; or

(ii) Thirty (30) days after publication of the notice of a final EIS under this paragraph.

(3) The Commission will allow no fewer than 45 days for comment on a draft EIS.

(4) The Commission may waive the time periods in paragraphs (i)(2) and (3) of this section when engaged in rulemaking under the Administrative Procedure Act or other statute for the purpose of protecting the public health or safety, or, in any proceeding, upon a finding of compelling reasons of national policy. To the extent practicable, the Commission will consult with the EPA regarding the waiver. A notice to waive time period will be published in the **Federal Register.** When time periods are waived under this subparagraph, the Commission may publish a decision on the final rule simultaneously with publication of the notice of the availability of the final EIS.

(5) If the notice of a final EIS is published within 90 days after a notice of a draft EIS is published in the **Federal Register,** the minimum 30-day period and the minimum 90-day period under paragraph (i)(2) of this section may run concurrently.

(6) The Commission may extend prescribed periods for good cause. Mere failure to file timely comments will not be a sufficient reason for granting an extension of a period.

(j) *Emergencies.* Where emergency circumstances make it necessary to take action with significant environmental impact without observing the provisions of these regulations, the Commission may consult with the CEQ and EPA about alternative arrangements. The Commission will limit those arrangements to actions necessary to control the immediate effects of the emergency. Other actions remain subject to NEPA review.

§ 3d.14 Interagency resolution of disagreements on environmental matters.

(a) This section provides procedures for resolution of disagreements between the Commission and another Federal agency about which agency will be the lead agency or about proposed major Federal actions that might cause significant adverse environmental effects.

(b) *Lead agency disputes.* If the Commission and another Federal agency that shares responsibility for a proposed Federal action are unable to agree on a lead agency designation, the Commission staff will refer or participate in referral of the matter to CEQ for determination under 40 CFR 1501.5.

(c) *Substantive environmental disputes.* (1) Any environmental issue or

dispute concerning a proposed major Federal action significantly affecting the quality of the human environment related to a Commission action or proceeding pursuant to administration of the Commission's regulatory decisionmaking functions under the Natural Gas Act, the Federal Power Act, the Department of Energy Organization Act, the Interstate Commerce Act, the Natural Gas Policy Act, the Power Plant and Industrial Fuel Use Act, the Alaska Natural Gas Transportation Act, or the Public Utility Regulatory Policies Act must be resolved exclusively by Commission decision and any judical review of Commission decision provided by law. Any person wishing to participate in Commission decisionmaking processes in such a case may seek to intervene in the proceeding as an interested party, under §§ 1.8 or 3d.10(e)(1) of this chapter.

(2) If an environmental issue of dispute within the scope of paragraph (c)(1) of this section is referred to CEQ pursuant to 40 CFR Part 1504 for a recommendation to the Commission, any recommendation from CEQ will be entered in the record as advisory only, if CEQ is not a party to the Commission proceeding.

(d) *Referral of substantive issues.* If the Commission, acting in a matter other than one pursuant to administration of its regulatory decisionmaking functions under the Natural Gas Act, the Federal Power Act, the Department of Energy Organization Act, the Interstate Commerce Act, the Natural Gas Policy Act, the Power Plant and Industrial Fuel Use Act, the Alaska Natural Gas Transportation Act, or the Public Utility Regulatory Policies Act, such as a legislative proposal, and another agency sharing responsibility for a proposed major Federal action are unable to resolve any environmental disagreements, the Commission will refer the problem to the CEQ for resolution under 40 CFR Part 1504.

§ 3d.15 Coordination of NEPA activities.

The Commission's Advisor on Environmental Quality will be responsible for coordinating the Commission's NEPA activities and for coordinating the Commission's environmental policies with CEQ and the Department of Energy.

Subpart C—Environmental Documents

§ 3d.20 Environmental assessments.

(a) An EA is an environmental document, defined in 40 CFR 1508.9, prepared by the Commission staff to evaluate the environmental impact of proposed actions not categorically excluded from the NEPA process or normally requiring an EIS under § 3d.10(c). The Commission staff will determine the scope and content of each EA to ensure that sufficient information is available to determine whether the proposed action would be a major Federal action significantly affecting the quality of the human environment.

(b) The Commission staff will prepare an EIS for each proposed action determined under § 3d.10(c) or on the basis of the EA to be a major Federal action significantly affecting the quality of the human environment. In making that determination, the staff will consider at least:

(1) The magnitude of the proposed action, with respect to:

(i) The extent of Commission control or influence over the proposed action by virtue of its discretionary authority; and

(ii) The extent of the commitment of resources entailed.

(2) The significance of the environmental impacts of the proposed action, with respect to:

(i) The overall cumulative impact of relevant past, present, and reasonably foreseeable future actions by the Commission or other entities;

(ii) The potential for both short- and long-term degradation of the quality of the human environment, and the curtailment of the range of beneficial uses of the environment;

(iii) The effects on management, allocation, or consumption of important, scarce or nonrenewable resources;

(iv) The presence of responsible opposing views concerning the environmental impacts; and

(v) The unique characteristics of the environment to be affected.

(c) A separate EA need not be prepared for a proposed action for which the Commission or another Federal agency has already prepared an EA or EIS, if that document affords a currently valid evaluation of the environmental impact of the proposed action. In such a case, the Commission staff may adopt the EA or EIS of another Federal agency, in whole or in part, according to procedures in § 3d.13(d).

§ 3d.21 Environmental impact statement.

(a) Unless the Commission adopts all or part of an EIS prepared by another agency as described in § 3d.13(c), each EIS will be prepared directly by Commission staff or a contractor selected by the Commission, or where appropriate, by or in conjunction with a cooperating agency. Any contractor will be required to certify itself free of financial or other interest in the proposed action. Any EIS prepared under contract will be independently evaluated by the Commission staff before it is circulated.

(b) Data and analyses in an EIS will be commensurate with the importance of the impact of the proposed action, with less important material summarized, consolidated, or simply referenced. Useless bulk in an EIS will be avoided and the staff will concentrate effort and attention on important issues. Unpublished material, if necessary for a through understanding of the environmental impacts of a proposed action, may be included in an appendix.

(c) *Contents.* (1) *Format.* The Commission will normally use the following standard EIS format:

(i) Cover sheet.

(ii) Summary.

(iii) List of agencies, organizations, and persons to whom copies of the statement are sent.

(iv) Table of Contents.

(v) Description of proposed action and the need for it.

(vi) Affected environment.

(vii) Environmental impacts of the proposed action.

(viii) Analysis of alternatives.

(ix) Staff conclusions on significant environmental matters.

(x) References.

(xi) List of preparers.

(xii) Appendices (if any).

(2) *Cover sheet.* The cover sheet will include:

(i) A list of the responsible agencies, including the lead agency and any cooperating agencies;

(ii) The title of the proposed action that is the subject of the EIS (and, if appropriate, the titles of related cooperating agency actions), including reference to the states and counties (or other jurisdictions, if applicable) where the action would occur;

(iii) The name, address, and telephone number of the person at the Commission who can supply further information;

(iv) A designation of the EIS as a draft, final, or draft or final supplement;

(v) A one paragraph abstract of the EIS;

(vi) The date by which comments must be received; and

(vii) For a draft EIS only, a statement of the procedures for intervening in the Commission proceeding on the subject proposal.

(3) *Summary.* Each EIS will contain a summary of the EIS. The summary will stress the major conclusions, areas of controversy (including issues raised by agencies and the public), and the issues to be resolved (including the choice among alternatives). The summary normally will not exceed 10 pages.

(4) *Description of the proposed action and the need for it.* The proposed action and its objectives will be briefly described. Factors to be covered include the location and duration of the proposed action, historical information necessary to place it in proper perspective, its relationship to other current or future projects of programs of Federal, state, or local governments, private industry, or non-Federal applicants, its overall physical description, environmental and safety

controls, and mitigative measures, including plans for site restoration.

(5) *Affected environment.* The EIS will succinctly describe the environment of the area to be affected by the proposed action. The description will be no longer than is necessary to understand the effects of the proposed action.

(6) *Environmental impacts of the proposed action.* (i) The EIS will identify and analyze the probable direct and indirect environmental effects [40 CFR 1508.8] of the proposed action, including the effects of proposed mitigative measures. The analysis will describe: the effects (beneficial and adverse) on the biological, physical, and socio-economic environment which could be caused by the proposed action, the magnitude and importance of each effect, and the time periods in which these effects are anticipated.

(ii) The analysis will discuss the extent to which the proposal will conform to, or conflict with, any Federal, state, or local statutes, regulations, standards, limitations, or policies respecting environmental quality, including air and water quality, wastes, pesticides, and land use. The analysis will assess, with respect to probability of occurrence and magnitude of consequences, the risks of environmental degradation and damage to the society from:

(A) Potential accidents or failures, whether attributable to natural or non-natural causes, associated with the proposed action;

(B) Normal operations associated with the proposed action; and

(C) To the extent practicable, termination and abandonment of facilities or services associated with the proposed action.

(iii) The EIS will address the issues in section 102(2)(C) of NEPA: adverse environmental effects that will be unavoidable if the proposal is implemented, the relationship between short-term uses of the human environment and the maintenance and enhancement of long-term productivity, any irreversible or irretrievable commitments of resources that would be involved in the proposal should it be implemented, possible conflicts between the proposed action and the objectives of Federal, regional, state, local and (in the case of an Indian reservation) tribal land use planes, policies, and controls for the area concerned, and the natural or depletable resource requirements and conservation potential.

(7) *Analysis of alternatives.* (i) *Factual evaluation.* The EIS will present factual evaluations of the environmental impacts of the full range of reasonable alternatives to the proposed action in a concise, but sufficiently informative, manner. In particular, the EIS will discuss reasonable alternatives to the proposed action that might be taken to avoid or mitigate adverse environmental impacts.

(ii) *Examples of alternatives.* The alternative of taking no action will always be evaluated. Examples of other potential alternatives include: postponing action, taking action of a significantly different nature that would provide similar benefits with different environmental impacts, and modification of the designs or details of the proposed action which would alter its environmental impact.

(iii) *Comparative evaluation.* The EIS will include a comparative evaluation of the environmental impacts of the proposed action and each reasonable alternative. If an existing EIS contains an analysis of an alternative to the proposed action, its treatment of that alternative may be summarized and incorporated by reference, if the earlier treatment is still current and relevant to the objective of the proposed action. The range of alternatives discussed in an EIS will not be limited to measures that the Commission has authority to implement.

(8) *Staff conclusions on significant environmental matters.* The EIS will contain the staff's conclusions, which may include, but need not be limited to, sumaries of: the significant environmental impacts of the proposed action, the staff's preferred alternatives, if any, and any alternative to these which would have less severe

environmental impacts; any mitigative measures proposed by the applicant, as well as additional mitigation measures that might be more effective; any environmental impacts of the proposed action that cannot be mitigated; and reference to any pending, completed, or recommended studies that might provide base-line data or additional data on the proposed action.

(9) *References.* This EIS will contain a list of reports, literature, reference works and other source material cited or used in the text.

(10) *List of preparers.* The EIS will list the names, together with a brief summary of the qualifications (expertise, experience, professional disciplines) of the persons who were primarily responsible for preparing the EIS or significant background papers.

(11) *Appendix.* If the Commission staff prepares or adopts an appendix to an EIS, the appendix will:

(i) Consist of material prepared in connection with an EIS (as distinct from material incorporated by reference);

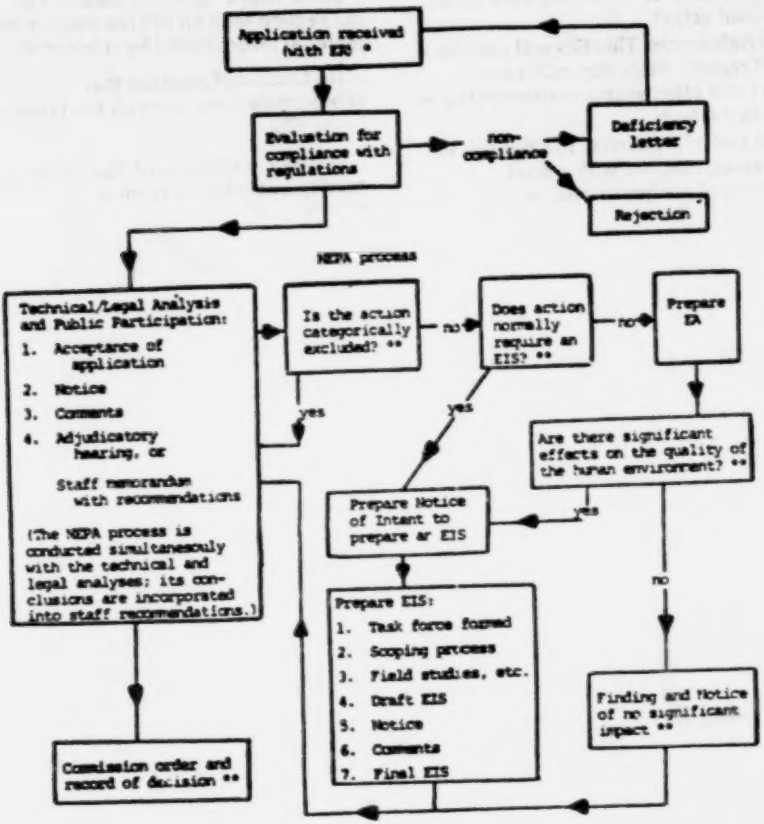
(ii) Consist of material that substantiates any analysis fundamental to the EIS.

(iii) Be circulated with the EIS or be readily available on request.

* * * * *

APPENDIX C

FERC DECISIONMAKING PROCESS UNDER NEPA


Application received with ER *
Evaluation for compliance with regulations
non-compliance
Deficiency letter
Rejection
NEPA process
Technical/Legal Analysis and Public Participation:
1. Acceptance of application
2. Notice
3. Comments
4. Adjudicatory hearing, or
Staff memorandum with recommendations
(The NEPA process is conducted simultaneously with the technical and legal analyses; its conclusions are incorporated into staff recommendations.)
Is the action categorically excluded? **
no
Does action normally require an EIS? **
no
Prepare EA
yes
yes
Are there significant effects on the quality of the human environment? **
yes
Prepare Notice of Intent to prepare an EIS
Prepare EIS:
1. Task force formed
2. Scoping process
3. Field studies, etc.
4. Draft EIS
5. Notice
6. Comments
7. Final EIS
no
Finding and Notice of no significant impact **
Commission order and record of decision **

* An ER is not required for categorically excluded actions.

** NEPA Decision Points.

¶ 32,035 Interstate Pipeline Transportation on Behalf of Other Interstate Pipelines

44 F. R. 51612 (September 4, 1979).

[18 CFR Part 284]

[Docket No. RM79-74]

Interstate Pipeline Transportation on Behalf of Other Interstate Pipelines; Proposed Rulemaking and Public Hearing

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (FERC) gives notice of a proposed rule which would permit interstate pipelines to transport natural gas for delivery to other interstate pipelines. A blanket certificate procedure would authorize such transportation without prior FERC approval of each individual transaction.

DATES: Request to participate at public hearing due by September 18, 1979. Public hearing on September 24, 1979. Written comments by September 24, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, Northeast, Washington, D.C. 20426 (Reference Docket No. RM79-74).

FOR FURTHER INFORMATION CONTACT: Robert C. Platt, Office of the General Counsel, 825 North Capitol Street, Northeast, Washington, D.C. 20426 (202) 357-8450.

I. Background

Section 311(a)(1) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3371(a)(1), enables the Commission to authorize transportation by an interstate pipeline on behalf of any intrastate pipeline or local distribution company. However, transportation by an interstate pipeline on behalf of a second interstate pipeline is beyond the scope of Section 311 of the NGPA. Such transportation arrangements require certificates of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act.

This gap in the Commission's section 311 authority has placed interstate pipelines at a competitive disadvantage in attaching short-term supplies. Unlike Section 311 authorizations which can be implemented on a self-executing basis (See 18 CFR 284.100 *et. seq*), certificates under Section 7(c) of the Natural Gas Act are issued only after a case by case review. Hence, under Section 311 an intrastate pipeline or local distribution company seeking to attach short term supplies through interstate pipeline transportation may implement such a transaction without prior Commission approval. However, if an interstate pipeline sought the same supply for its customers, the transaction would require the Commission to issue at least a temporary certificate before a second interstate pipeline could transport the natural gas to the purchasing interstate pipeline.

Similarly, when attaching long term supplies, and intrastate pipeline or a local distribution company may use Subpart B of Part 284 to commence service while an application for long term authorization is pending before the Commission. The lack of a blanket certificate procedure places interstate pipelines at a competitive disadvantage in attaching such long term supplies as well. In view of the Commission's desire to increase system supplies available to interstate pipelines as well as to reduce the regulatory burden on the transporting interstate pipelines, the Commission has determined that case-by-case review of such transportation

arrangements is inconsistent with the public interest at this time.

In place of individual applications directed to a single transportation arrangement, the proposed rule would allow the transporting interstate pipeline to apply for a one time blanket certificate which would authorize all transportation services on behalf of other interstate pipelines for periods of up to two years. Although such transportation would remain subject to the Commission's Natural Gas Act jurisdiction, the terms and conditions attached to the certificate would be identical to those imposed by Subpart B of Part 284.

The construction of facilities incidental to transactions authorized under blanket certificates is authorized by § 157.7(b)(4) of this chapter.

II. Public Convenience and Necessity

The Commission proposes to find that the transportation authorized by these blanket certificates is required by the present or future public convenience and necessity.[1] Several factors underlie this finding. First, the natural gas will enter the general system supplies of an interstate pipeline, rather than benefiting specific end-users. Second, the natural gas will be subject to end-use allocation under Commission approved curtailment plans. Third, individual transactions under the blanket certificate are short-term (of two years or less) and would not result in a disruption of markets upon which interstate pipelines have traditionally relied. Fourth, permitting these transactions on a self-implementing basis will eliminate a competitive disadvantage which interstate pipelines face when attempting to attach short-term supplies.

III. Section by Section Analysis

Proposed paragraph (a) clarifies the relationship between the blanket certificate and the self-executing authorizations in Subpart B of Part 284, *i.e.* the blanket certificate covers only natural gas transported by interstate pipelines for the system supplies of other interstate pipelines. Neither long term transportation arrangements nor the transportation of the interstate pipeline's own natural gas are covered by the blanket certificate.

Proposed paragraph (b) indicates the limited nature of the blanket certificate. Although the certificate is of indefinite duration, individual transactions authorized under it are limited to two years under § 284.102, subject to extension under § 284.105.

Proposed paragraph (c) prescribes an abbreviated application procedure. Because data on individual transactions will be filed within thirty days of the commencement of each transaction, detailed data is not required for the blanket certificate application.

Proposed paragraph (d) incorporates the conditions set forth in Subpart B of Part 284 by reference as amended from time to time.

Proposed paragraph (e) frees the holder of the blanket certificate from any service obligation after each underlying transportation contract expires. This pregranted abandonment places the holder of the blanket certificate in an equivalent position to a transporter authorized under Section 311(a)(1) of the NGPA.

Proposed paragraph (f) makes clear that interstate pipelines which elect to not obtain a blanket certificate may still obtain Section 7(c) authorization on a case-by-case basis.

IV. Written Comment Procedure

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to 4:30 p.m., EDT., September 24, 1979, will be

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[1] Similar blanket transportation certificates have been issued in the past. High Island Offshore System and U-T Offshore System, Docket Nos. CP75-104 and CP78-118, order issued June 12, 1978.

considered by the Commission prior to the promulgation of final regulations. All written submissions will be placed in the Commission's public file and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NW., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM79–74.

V. Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on September 24, 1979, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., E.S.T., on September 18, 1979.

Request to participate in the hearing should include a reference to Docket No. RM79–74 as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m. on September 21, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement.

Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Act, 15 U.S.C. 717 *et seq;* Department of Energy Organization Act, Pub. L. 95–91; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to add a new Subpart G to Part 284, Subchapter I, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. The table of sections for Part 284 is amended by the addition of a new Subpart G, to consist of §§ 282.220 and 282.221:

Subpart G—Blanket Certificates Authorizing Transactions in Accordance With Subparts B Through D.

Sec.

284.220 [Reserved]

284.221 Transportation on behalf of interstate pipelines.

2. Part 284 is amended by the addition of new sections 284.220 and 284.221, to read as follows:

§ 284.220 [Reserved]

§ 284.221 Transportation on behalf of interstate pipelines.

(a) *Applicability.* This section applies to the transportation of natural gas by an interstate pipeline on behalf of any other interstate pipeline. Transportation of natural gas on behalf of an intrastate pipeline or a local distribution company is authorized by Subparts B, C, and F of this part.

(b) *Blanket certificate.* Upon application therefor, the Commission will conduct a hearing pursuant to section 7(c) of the Natural Gas Act and § 157.11 of this chapter to determine whether the proposed service is required by public convenience and necessity. The Commission will issue to an interstate pipeline to which this section is applicable, a blanket certificate authorizing such pipeline company to transport natural gas for the system supply of any other interstate pipeline, to the same extent and in the same manner as transportation on behalf of intrastate pipelines is authorized by Subpart B of this part.

(c) *Application procedure.* Applications for blanket certificates shall state:

(1) The name of the applicant, and

(2) A statement that the applicant will comply with the conditions in paragraph (d) of this section.

(d) *General conditions.* (1) Any transaction authorized under a blanket certificate shall be subject to the same terms and conditions that would apply if the transaction were authorized by Subpart B of this part (as such may be amended from time to time).

(2) Any filings made with the Commission reporting individual transactions shall reference the docket number of the proceeding in which the blanket certificate was granted.

(e) *Pregrant abandonment.* Abandonment of transportation services pursuant to section 7(b) of the Natural Gas Act is authorized upon the expiration of the contractual term of each individual transportation arrangement.

(f) *Interstate pipelines without blanket certificates.* An interstate pipeline which does not obtain a blanket certificate may apply for a separate certificate of public convenience and necessity for each transportation service provided to any other interstate pipeline.

¶ 32,036 Determinction of Alternative Fuels for Essential Agricultural Users

44 F. R. 51993 (September 6, 1979).

[18 CFR Part 281]

[Docket No. RM79-40]

Determination of Alternative Fuels for Essential Agricultural Users

Issued August 29, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Section 401(b) of the Natural Gas Policy Act provides that the Commission determine, in consultation with the Secretary of Agriculture whether alternative fuels are economically practicable or reasonably available for essential agricultural users to use in lieu of natural gas. This rule proposes to find that residual fuel oil and coal are economically available for those who have used such fuel at any time since 1973. If this rule is adopted, essential agricultural users who have alternate fuel available will be taken out of the Priority 2 curtailment category; they will be treated as they have been under the interstate pipeline's curtailment plan.

DATE: Written comments by September 28, 1979. Public Hearing on September 24, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., N.E., Washington, D. C. 20426.

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Office of the General Counsel, Room 8000, 825 North Capitol St., N.E., Washington, D. C. 20426, (202) 357-8455.

I. Background

On May 2, 1979, the Commission issued a notice of proposed rulemaking in the above referenced proceeding (44 FR 27894, May 9, 1979). The proposed rule would have established procedures for evaluating, on a facility-by-facility basis, the reasonable availability and economic practicability of alternative fuel for essential agricultural uses, as called for by section 401(b) of the Natural Gas Policy Act of 1978 (NGPA).

The proposed rule was opposed by most who submitted written comments. The position most strongly and convincingly argued was that the Commission should adopt a generic approach to determine the availability and practicability of various fuels as alternatives to natural gas by essential agricultural users. The Commission is persuaded by the comments and therefore proposes a rule different than the rule proposed in the Notice of May 2, 1979. Unlike the rule proposed in the earlier notice, the rule proposed herein is not limited to establishing procedures, but makes a substantive determination concerning the reasonable availability and economic practicability of certain alternative fuels to natural gas, for the immediate future.

A. Statutory Provisions

Under section 401(b) of the NGPA, the protection from curtailment required by section 401(a) does not apply to essential agricultural uses "[i]f the Commission, in consultation with the Secretary of Agriculture, determines, by rule or order, that use of a fuel (other than natural gas) is economically practicable and that the fuel is reasonably available as an alternative for any agricultural use of natural gas. . . ." The rule proposed in this notice provides for that determination for certain fuels.

Section 401 of the NGPA seeks to assure that natural gas required for essential agricultural uses will not be curtailed unless curtailment is required to protect the needs of certain enumerated high priority users. Section 401 of the NGPA establishes a curtailment scheme under which the Secretary of Agriculture determines the volumetric amounts required for

essential agricultural uses, the Secretary of Energy establishes curtailment priorities, and the Federal Energy Regulatory Commission (Commission) establishes procedures under which the curtailment plans of interstate pipelines carry out the Congressional policy to provide agricultural users certain protections from curtailment.

Pursuant to section 403(b) of the NGPA and section 402(a)(1)(E) of the Department of Energy Organization Act, the Commission is charged with implementing the rules mandated by section 401 under its authority to establish, review, and enforce curtailments under the Natural Gas Act. On May 2, 1979, the Commission issued a rule carrying out its responsibilities under section 401(a) of the NGPA.[1] Under that rule, most customers of interstate pipelines are required to re-examine data used to determine base period volumes for curtailment plans in order to identify which volumes qualify for the newly defined Priority 1. In addition, pipelines are required to include in their curtailment plans a new Priority 2, which will contain requirements necessary to serve essential agricultural uses as defined by the Secretary of Agriculture.

As indicated above, however, the provisions of section 401(a), which protect deliveries of natural gas for essential agricultural uses, do not apply if the Commission determines, in consultation with the Secretary of Agriculture, that an alternative fuel is economically practicable and reasonably available. In order to give effect to this section, the Commission issued a notice of proposed rulemaking in this proceeding on May 2, 1979 and is reassessing this proposed rulemaking.

B. The First Proposed Rule

The rule proposed in the notice of May 2, 1979 would have established a procedure of case-by-case rulemaking applicable to certain essential agricultural establishments that use large amounts of natural gas as boiler fuel. To determine if alternative fuel is reasonably available and economically practicable for such uses, the proposed rule required an essential agricultural use establishment to file a petition for rulemaking and accompanying data if the establishment (1) requested to have natural gas used as boiler fuel classified as a Priority 2 entitlement by an interstate pipeline, (2) had the capacity to burn over 300 Mcf of gas on a peak day, and (3) had used a fuel other than natural gas for 60 consecutive days during 1976 through 1978. A rulemaking proceeding would then have been conducted to determine whether the alternative fuel was reasonably available and economically practicable for that essential agricultural use establishment.

C. Comments on the First Proposed Rule

The deadline for filing comments on the proposed rule was May 30, 1979. A public hearing was held on May 23, 1979. At the hearing, interested persons were given the opportunity to present their views to a panel consisting of three representatives of the Commission, a representative of the Economic Regulatory Administration, and a representative of the Department of Agriculture.

The overwhelming majority of those filing comments opposed the proposal for individual rulemakings. Some emphasized the administrative problems that would be created by such a plethora of individual rulemakings. Others maintained that the filing requirements were unduly burdensome. Many of the commentators suggested that a generic determination of the reasonable availability and economic practicability of specific fuels would be preferable. Commentators urged that DOE has sufficient data available to make this determination with reference to certain fuels.

II. Basis of the New Proposal

Upon consideration of the comments addressing this issue, the Commission has decided to propose a different rule, providing for a generic determination rather than the case-by-case approach orginially suggested. Specifically, the

rule proposed herein makes the substantive determination that, at present and over the next heating season, residual fuel oil and coal are generally economically practicable and reasonably available alternative fuels for any essential agricultural use establishment that has used either of those fuels in the past six years and retains the physical capability to use them now. In addition, the rule presumes that new boilers [2] capable of using more than 300 Mcf of gas per day have an economically practicable alternative fuel reasonably available.

The Commission recognizes that particular circumstances may warrant exception to the general rule. In cases where application of the rule would result in the situations sought to be avoided by Congress when it enacted section 401, agricultural users should file for an adjustment under section 502(c) of the NGPA and § 1.41 of the Commission's Rules of Practice and Procedure. The Commission's section 502(c) procedures will be discussed in more detail below.

The rule we are now proposing would affect only agricultural users that have demonstrated an ability to use certain alternative fuels in the past and that have retained the necessary physical capability to use those fuels in view of natural gas. The rule would also apply to new boilers installed after August 29, 1979 which are capable of using more than 300 Mcf of natural gas per day. The ability to use an alternative fuel does not, by itself, disqualify a particular agricultural establishment from Priority 2 classification. The particular alternative fuel that the establishment is capable of using must meet the two-pronged test of being economically practicable and reasonably available.

The proposed rule makes the determination that at this time and at least for the forthcoming winter heating season, the data available establish that residual fuel oil and coal are economically practicable and reasonably available to all essential agricultural users capable of using these fuels.[3] The Commission believes it is not in a position at this time to make such a finding with respect to middle distillates.

In making the findings concerning relative availability of residual fuel oil and middle distillates, the Commission reaffirms the general position it took with respect to the Fuel Oil Displacement Rule, Order No. 30 and Rehearing, Order No. 30–A.[4] That rule allows the burning of excess natural gas that is surplus to a pipeline or distributor's current needs in boilers to displace the use of middle distillates and residual fuel oil. When that aspect of Order 30 that might result in displacement of residual fuel oil was challenged, the Commission on rehearing stated that Order 30 was not based upon a shortage of residual fuel oil *per se*.

"First, there does appear to be excess deliverability of natural gas which may be utilized to displace fuel oil. According to Department of Energy estimates, even if all essential agricultural users are given 100% of their needs, 341 additional Mcf of natural gas deliverability remains.[9] Second, Order No. 30 is prompted by a shortage of middle distillate fuel oil.[10] The distillate shortage has been documented in the record established in Docket No. RM79–34.[11]

However, BUG's suggestion that Order No. 30 authorization be conditioned only upon middle distillate displacement must be rejected. While the objective of Order No. 30 centers upon displacing middle distillate fuel oil, this Commission is unable to determine that this objective would be best advanced by limiting authorization solely to transactions involving the direct displacement of middle distillate fuel oil with natural gas. The refinery and distribution of petroleum products is a vast and complex area with which the Commission has imperfect knowledge. Nonetheless, it is clear to us that transactions involving the displacement of residual fuel oil could in some instances have the same ultimate beneficial impact on middle distillate consumers as would a transaction involving the direct displacement of middle distillates. For example, displacing residual oil with natural gas will increase availability of residual fuel oil to other users. If such other users have the capability to burn either residual or middle distillates, the increased supply and/or lower price of residual fuel oil

to these users may result in the displacement of middle distillate fuel oil with residual fuel oil.

In addition, residual oil can often be further refined to produce additional distillate fuel oil. Some refiners may find it profitable to reduce yields of residual fuel oil and maximize yields of middle distillate fuel oil, if Order No. 30 reduces demand for residual fuel oil.

These illustrations suggest that there is not a sharp division between residual fuel oil and middle distillate oil, either as to how such products are refined or how they are ultimately consumed. Transactions involving the displacement of residual fuel oil may, ultimately, have the same beneficial impact on distillate supplies as transactions involving the direct displacement of middle distillate fuel oil.

Further, the objective of Order No. 30 is not only to displace middle distillate fuel oil, but also to reduce our dependence on imported oil. This dependence has created the need for the President to declare the previously mentioned National Energy Supply Shortage. Because roughly one million barrels per day of residual fuel oil is imported, the Order No. 30 program accordingly will directly reduce the petroleum imports. Accordingly, the Commission, concludes that any decision to narrow the scope of Order No. 30 to permit only direct displacement of middle distillates could inhibit rather than enhance the purposes of the program."

The Commission believes that this view of relative fuel availability remains pertinent. However, the purpose of Order 30 (oil displacement) is substantially different than the purpose of this proposed rule which is to establish gas curtailment priorities. Order 30 provides for the displacement of fuel oils by *excess volumes of natural gas*. In contrast, the purpose of this proposed rule is to determine which users can most readily and economically switch to some other fuel should there be a *shortage of natural gas*. The Commission believes that residual fuel oil is reasonably available as a substitute should users need to use it in the face of a shortage; middle distillates, on the other hand, are not available for such purposes at this time.

A. Reasonable Availability of Fuels. Official statistics indicate there are reasonably adequate supplies of coal and residual fuel oil. DOE's *Monthly Energy Review* for July 1979 indicates that residual fuel oil is in relatively plentiful supply. Stocks for December 1978 exceeded 90 million barrels,[5] well above the 67 million considered the munimum acceptable level for that time of year.[6] So far this year, stocks have continuously exceeded the minimum acceptable level.[7] As of the end of May this year, residual fuel oil stocks were 13.5 percent greater than for the same month a year ago.[8] Approximately 48 percent of all the residual fuel oil (domestic refinery production plus imports) consumed in the U.S. during 1978 was high sulfur residual fuel oil.[9]

High sulfur oil, in general, sells for less than low sulfur oil. The following table shows domestic production and imports of high sulfur residual fuel oil plus end-of-month stocks for February 1979.

Source	Residual fuel oil (February 1979)[10]		
	High sulfur	Total	High sulfur
	(In millions of barrels)		(Percent)
U.S. refinery production	27,473	50,188	54.7
Imports	15,120	36,590	41.3
Subtotals	42,593	86,778	49.1
Stocks (end-of-month)	36,334	68,229	53.3
Grand total	78,927	155,007	50.9

[10] Energy Data Reports, Availability of Heavy Fuels Oils by Sulfur Levels, February 1979.

Compared to the same month a year ago, total residual stocks in February 1979 were 5.2 percent higher while high sulfur stocks were greater by 13.4 percent.[11]

Coal is also readily available to customers capable of using it. On an annual basis, production, not including imports, has historically exceeded domestic consumption. Additionally, stocks of bituminous and lignite coal at the end of April this year were 4.2 percent higher than they were twelve months earlier.[12]

The Commission has no information that would lead it to believe that supply situation of either residual fuel oil or coal is likely to change substantially in the forseeable future.

As discussed, the Commission has evaluated middle distillate availability in connection with Order No. 30 and has found that distillate fuel oil, including No. 4 fuel oil, is in short supply.[13] The nation's middle distillate supply as of the the end of July 1979, was about 165 million barrels. Although slightly above the minimum acceptable level for this time of year, it is 9% lower than one year ago.[14] (The Department of Energy estimates that distillate stocks must reach 240 million barrels to meet this coming winter heating season demand. Order No. 30–A at 4). Therefore the proposed rule does not contain a Commission determination that distillate fuel oil is reasonably available for essential argicultural uses at this time. It follows, therefore, that if an essential agricultural user can use only natural gas or middle distillates, the Commission would not consider such user to have a reasonably available alternative fuel.

As changes in the supply and demand of fuels occur, the Commission will have to consider from time to time the availability of various fuels and particularly the availability of middle distillates. However, the Commission does not intend to make such a reexamination until after the coming heating season. Also, any change in such determination would be made effective prospectively with a reasonable period for adjustment.

In sum, on the basis of the information available to it, the Commission proposes to find that residual fuel oil and coal are now, and will be during the coming winter heating season, reasonably available to essential agricultural use establishments capable of using either fuels. The Commission welcomes comment on the empirical support for its judgment that residual fuel oil and coal are readily available but middle distillates are not.

B. Economic Practicability

The Commission notes that the NGPA Conference Report provides some guidance on the meaning of "economic practicability". One of the reasons for the requirement is to avoid unnecessary increases in the cost of food.[15] Moreover, a fuel is not economically practicable if it would require a "switch to high-cost alternatives."[16]

The term "economically practicable" is also used as part of the alternative fuel test of section 402(b) (industrial process and feedstock uses). In discussing that section, the Conference Report says that "the term economically practicable" is intended to have the same meaning as the Commission's standard of economic feasibility under "extraordinary relief in curtailment cases."[17]

The Commission specifically requests comment on the "extraordinary relief" standard mentioned above. Is it an appropriate standard for determining economic practicability of alternative fuels under section 401(b) of the NGPA? If so, is it the only standard? How can it be applied? Does the phrase "economic feasibility" as used in the Conference Report apply only to the cost of converting a plant to the use of alternative fuel? Or does it apply to the cost of the fuel itself?[18] In other words, under the test of economic feasibility as used for extraordinary relief in curtailment cases, is a fuel other than natural gas economically practicable if its cost is disproportionately high compared to the cost of natural gas?

Because we are of the opinion that middle distillates may not be readily available, it is unnecessary to address the economic practicability of these fuels.

Whatever standard is used, it would appear that coal should be deemed an economically practicable alternative fuel. On a Btu basis, it appears to be the least expensive fuel available. The average price of coal delivered to an electric utility plant was $1.17 per MMBtu ($25.15 per ton) in March, 1979.[19] This is less than half the average price of oil $2.61 per MMBtu delivered to electric utilities at that time, and 28 percent less than the comparable price for gas ($1.63 per MMBtu).[20] Thus, on an absolute basis coal is, in general, less expensive than natural gas. Although the cost of fueling industrial coal fired boilers may well differ from the average cost incurred by electric utilities, it seems reasonable to assume that the relative cost of fuels to the electric utility industry will be similar for all users in general.

It also appears that residual fuel oil should be considered economically practicable. The table below shows the average nationwide prices paid for residual fuel oil and interstate natural gas by industrial customers from 1976 through April 1979.

Prices Paid by Industrial Customers for Residual Fuel Oil and Interstate and Natural Gas

	Residual fuel oil price [21]		Interstate P/L gas price to industrials [22]	Differential—residual versus gas [23]	
	High sulfur [24]	Total		High sulfur	Total
	(Dollars per million Btu)		(Dollars per 1,000 ft³)	(Dollars per 1,000 ft³)	
Year and month:					
1976	1.66	1.83	0.97	0.69	0.86
1977	1.85	2.10	1.32	.53	.78
1978	1.86	2.03	1.54	.32	.49
1979:					
January	1.90	2.25	1.92	(.02)	.33
February	1.95	2.33	1.95		.38
March	2.23	2.54	1.97	.26	.57
April	2.32	2.64	1.91	.41	.73

[21] *DOE Monthly Energy Review*, July 1979, at 88. The prices shown for residual fuel oil are retail prices converted from dollars per barrel to dollars per MMBtu. The conversion is based on a factor of 6,287,000 Btu/barrel. *Id.* at 108.

[24] Greater than one percent sulfur content.

[22] *Energy Data Report*, Financial Statistics of Electric Utilities and Interstate Natural Gas Pipeline Companies, December 1977, December 1978 and the months indicated for 1979. One Mcf of gas is the approximate equivalent of one MMBtu.

[23] Residual fuel oil prices less interstate gas prices.

While the price data indicate that residual fuel oil is more expensive than natural gas on an absolute basis, on a *relative* basis, residual fuel oil has become *less* expensive as an alternative fuel in recent years. Thus, it appears that for customers with the installed physical capability, residual fuel oil, especially high sulfur oil, is economically practicable as an alternative fuel for natural gas. Admittedly the above fuel oil prices do not reflect the recent hike in OPEC crude oil prices set in June of this year. However, we will continue to monitor residual fuel oil prices as well as the prices of other fuels during and after this initial rulemaking proceeding. On the average low sulfur residual fuel oil was about 31 cents per MMBtu (16.5 percent) more expensive than high sulfure residual fuel oil during 1978. The difference between low sulfur and high sulfur residual fuel oil prices increased to 59 cents per MMBtu in April of this year.[25]

The proposed rule does not assume the conversion of any facilities not presently equipped to use alternative fuels. Nevertheless, it is a common knowledge that new boilers can be constructed with dual fuel capability relatively inexpensively. Consequently, the proposed rule presumes that boilers capable of using over 300 Mcf per day and installed after 1979, are able to use an alternative fuel that is reasonably available and economically practicable.[26]

The proposed rule would measure a boiler's capacity on its manufacturer's nameplate rating, expressed in MMBtu's per hour for a 16 hour period. Although some boilers could be operated at a rate above or below the nameplate rating, the Commission believes that nameplate rating is the most objective, verifiable, administratively feasible standard to use in determining a boiler's capability. Generally, it is not considered efficient to limit a boiler's operation to an 8 hour day, but neither do all boilers operate 24 hours a day. The 16 hour period was selected, therefore, as a reasonable middle ground.

Some commentators on the rule first proposed in this docket argued that no fuel may be deemed economically practicable if it costs more than natural gas. These arguments were usually supported by a reference to the statement in the Conference Report that the "determination that an alternative fuel is 'economically practicable' shall not include a requirement to *switch* to *high* cost alternatives" (Emphasis added). The proposed rule applies only to new boilers with capacity in excess of 300 Mcf per day and to establishments already capable of using alternative fuels. Under this proposed rule, no agricultural use establishment will be required to switch fuels. Furthermore, the Commission does not believe that "higher cost" is the same as "high" cost.

Natural gas has long been and remains a relatively inexpensive fuel. Even so, may consumers have also used other fuels as a supplement to or in lieu of natural gas. We do not think that enactment of the NGPA suddenly made all higher cost fuels "economically impracticable". Nationwide the prices of alternative fuels relative to the price of natural gas have actually declined since 1974. See Appendix A.

As previously mentioned, the Commission is aware that the relative cost as well as availability of fuels is subject to change. The Commission will necessarily and of its own motion make new determinations on the basis of changes in circumstances. Nonetheless, any interested person may petition the Commission to initiate a rulemaking proceeding to make new determinations based upon changes in circumstances.

The Commission is aware that a generic rule on reasonable availability and economic practicability will not be fitted to the particular and unique circumstances of every person. Accordingly, any person may file for an adjustment to this rule. Under Section 502(c) of the NGPA the Commission grants adjustments to prevent hardship, inequity and unfair distribution of burden. The Commission does not wish to make the seeking of an adjustment burdensome. Therefore, the Commission seeks comment on what types of data are readily available to essential agricultural users and which would be useful in seeking an adjustment. It also seeks comment on what standards should be used in making determinations concerning adjustments.

III. Discussion of the Proposed Rule

Section 281.301. This section describes the purpose of this new subpart M —— to determine the economic practicability and reasonable availability of alternative fuels as prescribed in section 401(b) of the NGPA.

Section 281.302. This section sets forth the essential agricultural users which are subject to this alternative fuel determination. To be subject to this alternative fuel rule, an essential agricultural user must (1) have requested that natural gas be classified as priority 2 and (2) have the ability to use an alternative fuel.

Section 281.303. Sets forth definitions used in the subpart. "Ability to use" a

particular alternative fuel means that essential agricultural user has installed the physical capability to use the alternative fuel and that he has actually used the altenative fuel at some time beginning in 1974. "Alternative fuel" means coal or residual fuel oil. "Residual fuel oil" is defined as Nos. 5 and 6 fuel oil. "Coal" means lignite or any other rank of bituminous or anthracite coal. Other definitions include "boiler", "capacity", "combustion turbine", "diesel engine", "essential agricultural requirements", "essential agricultural use", and "Priority 2 entitlements".

Section 281.304. This section sets forth the general rule that the essential agricultural requirements of an essential agricultural user shall exclude volumes of natural gas for which it has the abaility to use alternative fuel. The rule also provides that a new boiler with the capacity in excess of 300 Mcf of natural gas per day and that is put into use for the first time after August 29, 1979, is deemed to have the ability to use alternative fuel. For purposes of this rule, a boiler excludes combustion turbine engine or a diesel engine. The rule further requires that any essential agricultural user which has already requested Priority 2 classification for requirements for which under this rule he would have alternative fuel must amend its request for Priority 2 treatment and reduce the volume from which it request Priority 2 treatment to exclude volumes for which he has alternative fuel.

A sample calculation of reduction in Priority 2 entitlements may be helpful. Assume an essential agricultural user has requested 1000 Mcf per day priority 2 entitlements. Of that amount, 500 is used as feedstock for which no alternative fuel has ever been used. The remaining 500 is used in a boiler which has installed capability to use residual fuel oil and which has at some time since 1974 used an alternative fuel. The boiler has the capacity to use 700 Mcf per day of natural gas. Section 281.304(b) would require the essential agricultural user to reduce its priority 2 requirements by 500 Mcf per day—the volume for which it has alternative fuel and for which it has requested priority 2 entitlements. The rule further requires that each distribution company and interstate pipeline which receives amended request for Priority 2 treatment because of alternative fuel availability forward these in accordance with the provisions of subpart B.

Section 281.305. This section requires that each essential agricultural user that has requested Priority 2 treatment for natural gas in excess of 300 Mcf on a peak day for boilers, diesel engines and internal combustion engines submit a statement to its direct supplier indicating the uses of the natural gas for which it has sought Priority 2 entitlements. The local distribution companies and interstate pipelines that receive these statements in accordance with subpart B.

IV. Comment Procedures

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79–40. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, September 28, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. The Commission will consider all timely comments before acting on matters proposed in this notice.

B. Public Hearings

A public hearing concerning this proposal will be held in Washington,

D.C. on September 24, 1979. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided that a written request to participate is submitted to the Secretary of the Commission at the address given above at least seven days before the date the hearing is to be convened. Requests to participate should include a reference to Docket No. RM79–40, should indicate the hearing in which the person making the request wished to participate, should indicate the amount of time desired, and should include a telephone number where the person making the request may be reached. The presiding officer is authorized to limit oral presentations at the public hearings both as to length and as to substance. Persons participating in the public hearings should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearings. Transcripts of the hearings will be available in the public file for this proceeding, Docket No. RM79–40, in the Commission's Office of Public Information.

(Natural Gas Act as amended, 15 U.S.C. 717–717w; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, it is proposed to amend Part 281, Chapter I of Title 18, Code of Federal Regulations, by adding a new Subpart C to Part 281 to read as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

Appendix A.—*Prices Paid by Electric Utilities for Selected Fuels*

[1973–April 1979]

Type of fuel	1973	1974	1975	1976	1977	1978	1979			
							Jan.	Feb.	Mar.	Apr.
	Cents per million Btu									
FUEL OIL [1]										
No. 2	114.9	217.3	215.5	235.1	264.3	271.9	293.8	309.0	320.9	308.1
All No. 6	79.2	190.6	201.1	195.3	219.8	211.8	227.8	240.3	258.0	263.8
High sulfur No. 6 [2]	81.7	184.5	170.5	168.7	199.9	186.7	189.8	190.4	227.5	232.3
Low sulfur No. 6 [2]	85.1	203.2	213.4	207.1	229.1	225.1	248.9	260.2	278.7	288.7
GAS [3]										
Firm	29.9	44.3	70.2	93.6	112.8	129.3	138.1	143.3	140.3	145.1
Interruptible	39.0	54.0	84.8	124.1	163.8	179.8	197.6	202.9	202.0	199.0
Weighted average	33.8	48.1	75.4	103.4	130.0	143.8	150.2	158.1	163.0	164.7
COAL [4]										
All grades	40.5	71.0	81.4	84.8	94.7	111.6	115.8	114.6	118.8	120.1

Price Differentials—Fuel Oil and Coal v. Gas

Fuel Oil v. Gas [1]										
No. 2	81.1	189.2	140.1	131.7	134.3	128.1	143.6	149.9	157.9	204.4
All No. 6	45.4	142.5	125.7	91.9	89.8	68.0	77.6	81.2	95.0	98.1
High sulfur No. 6	27.9	116.4	95.1	65.3	69.9	42.9	39.6	40.3	64.5	67.6
Low sulfur No. 6	51.3	155.1	138.0	103.7	99.1	81.3	90.7	101.1	115.7	124.0
Coal v. Gas [2]										
All types	6.7	22.9	8.0	(19.6)	(35.3)	(32.2)	(34.4)	(44.5)	(46.2)	(44.6)

[1] Weighted average prices of fuel oil delivered to steam electric plants. Excludes peaking fuel prices.
[2] Includes insignificant amounts of No. 4, and No. 5 oil, crude and topped crude. High sulfur oil has greater than 1 percent sulfur. Low sulfur oil less than 1 percent sulfur.
[3] Weighted average prices of gas delivered to steam electric plants. Excludes peaking prices. Includes small amounts of coke oven gas, refinery gas, and blast furnace gas.
[4] Weighted average price of all grades of coal delivered to electric utilities.
[5] Fuel oil prices less weighted average gas price.
[6] Coal price less weighted average gas price.

Source: FPC Form 423, *Annual Summary of Cost and Quality of Electric Utility Plant Fuels* (1973–1977). Data for 1978 and 1979 from FPC Form 423, Energy Data Reports, *Monthly Reports, Costs and Quality of Fuels for Electric Utility Plants*. Note: April 1979 data are preliminary.

1. Part 281 is amended in the Table of Contents by adding a new subpart C to read as follows:

PART 281—NATURAL GAS CURTAILMENT

* * * * *

Subpart C—Alternative Fuel Determination

Sec.
281.301 Purpose.
281.302 Applicability.
281.303 Definitions.
281.304 General Rule.
281.305 Filing Requirements.

2. Part 281 is amended by adding a new Subpart C to read as follows:

Subpart C—Alternative Fuel Determination

§ 281.301 Purpose.

The purpose of this subpart is to determine the economic practicability and reasonable availability of alternative fuels, as prescribed in Section 401(b) of the NGPA, for essential agricultural users that seek Priority 2 entitlements for natural gas.

§ 281.302 Applicability.

This subpart applies to each essential agricultural user that:

(a) Requests that natural gas be classified as Priority 2 entitlements by an interstate pipeline under § 281.207; and

(b) Has the ability to use alternative fuel.

§ 281.303 Definitions.

For purposes of this subpart:

(a) "Ability to use" a particular alternative fuel means that an essential agricultural user has installed the physical capability to use the alternative fuel and has used that alternative fuel (in any amount) at any time after 1973, for an essential agricultural use.

(b) "Alternative fuel" means coal or residual fuel oil.

(c) "Boiler" means a fuel burning device, other than a combustion turbine or diesel engine, used for generating steam or used for generating high temperature hot water that is used for space heating, manufacturing processess, or generating electricity.

(d) "Capacity" means the volumes of natural gas used if the boiler is operated at nameplate rated capacity for a continuous 16 hour period.

(e) "Coal" means lignite or any other rank of bituminous coal or anthracite coal.

(f) "Combustion turbine" means an external combustion engine that uses gaseous or liquid fuel other than residual fuel oil for generating shaft horsepower.

(g) "Diesel engine" means an internal combustion engine that uses gaseous or liquid fuels other than residual fuel oil for generating shaft horsepower.

(h) "Essential agricultural requirements" means volumes of natural gas certified by the Secretary of Agriculture and calculated in accordance with 7 CFR § 2900.4.

(i) "Essential agricultural use" means essential agricultural use as defined in § 281.203(a)(2).

(j) "Priority 2 entitlements" means essential agricultural requirements of an essential agricultural use establishment that an interstate pipeline classifies as Priority 2 in its curtailment plan in accordance with Subpart B.

(k) "Residual fuel oil" means Nos. 5 and 6 oil, Bunker C, and Navy Special as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM, D396 [Nos. 5 and 6 oils].

§ 281.305 General rule.

(a)(1) The essential agricultural requirements of an essential agricultural user shall exclude volumes of natural gas for which it has the ability to use alternative fuel.

(2) Any boiler that has a capacity in excess of 300 Mcf of natural gas per day and that is put into service for the first time after August 29, 1979, shall be deemed to have alternative fuel.

(b) Any essential agricultural user which has requested Priority 2 classification for natural gas for which it has the ability to use alternative fuel shall reduce its essential agricultural requirements calculated under § 281.207 to reflect the exclusion of volumes of natural gas for which it has the ability to use alternate fuel as determined in § 281.304(a) and file an amended request for Priority 2 classification in accord with Subpart B.

(c) Each local distribution company and interstate pipeline which received amended requests for Priority 2 classification shall make filings and adjustments necessary under Subpart B.

§ 281.305 Additional filing requirements.

(a) *Essential agricultural users.* (1) No later than November 1, 1979, an essential agricultural user that has made, in accordance with § 281.211(b)(1) of subpart B, a request for classification of essential agricultural use entitlements in excess of 300 Mcf on a peak day as Priority 2 entitlements shall submit to the local distribution company supplier or the direct interstate pipeline supplier, as appropriate, a statement setting forth:

(i) The requirements of each boiler, (B) combustion turbine and (C) diesel engine that has a capacity in excess of 300 Mcf per day and for which Priority 2 entitlements have been requested.

(ii) Any fuel other than natural gas which has been used in the boiler, combustion turbine or diesel engine.

(2) The statement under this paragraph shall be signed by a responsible official of the essential agricultural user. The official shall swear or affirm that the statements are true to the best of his information, knowledge, and belief.

(b) *Local distribution companies.* Local distribution companies and interstate pipelines that receive statements under § 281.305(a) shall forward copies of all such statements to the interstate pipelines to whom requests for classification of Priority 2 entitlements were made under § 281.211(b)(a).

— Footnotes —

[1] Order No. 29, Docket No. RM79-15. In a separate rulemaking the Commission promulgated an interim rule giving effect to Section 401 for the period of April 1, 1979, to October 31, 1979. (Docket No. RM79-13, March 8, 1979). The permanent rule of Order No. 29 affects deliveries of natural gas for the winter heating season of 1979-1980 and thereafter.

[2] New boilers are those boilers installed after August 29, 1979.

[3] The Commission hopes to make an alternative fuel rule effective for this winter heating season. The Commission has requested staff to do an environmental assessment of the proposed rule. Technical Staff has concluded on the basis of its environmental assessment that an environmental impact statement is not necessary. However, should the Commission determine an environmental impact statement is necessary it shall issue one for public comment before acting on a permanent curtailment rule. Nonetheless, it is possible that an interim rule on alternative fuel could be issued before completion of the environmental impact statement, should one be found necessary.

[4] Draft Order 30, approved in principle, August, 1979. Order 30-A, issued May 25, 1979. *Fed. Reg.* 30323.

[5] *DOE Monthly Energy Review*, July, 1979 at 42.

[6] *DOE Weekly Petroleum Status Report*, August 3, 1979, at 9. Estimated minimum acceptable level is defined as the level to which stocks may fall without disruption of customer deliveries or the creation of spot shortages.

[7] *Id.* at 20.

[8] *DOE Monthly Energy Review*, July 1979, at 42.

[9] *See* Energy Data Reports, Availability of Heavy Fuel Oils by Sulfur Levels, December 1978. High sulfur residual fuel oil is that residual fuel oil which contains greater than 1 percent sulfur content by weight.

[9] Further Comments of the Department of Energy submitted May 7, 1979, page 11.

[10] "[M] any residential, commercial and small industrial fuel oil customers will be particularly affected by high-priced and possibly inadequate distillate fuel oil. It is this Commission's responsibility to afford these users, who would be considered 'high-priority' if served by natural gas, relief within our discretion so long as this relief within our discretion so long as this relief does not come at the expense of other high-priority users." Order No. 30 at page 7.

[11] Further Comments of the Department of Energy, submitted May 7, 1979, at page 2.

[11] *See* Energy Data Reports, Availability of Heavy Fuel Oils by Sulfur Levels, February 1978 at 2 and February 1979 at 3.

[12] *DOE Monthly Energy Review*, July 1979, at 58.

[13] Order No. 30, Docket No. RM79-34, Final Rule, May 17, 1979, at 7. See also, Order No. 30-A, Order on Rehearing.

[14] *DOE Weekly Petroleum Status Report*, August 3, 1979, at 17.

[15] The Conference Report does indicate that one of the reasons for the requirement is to avoid unnecessary increases in the cost of food. H.R. Report No. 95-1752, 95th Cong., 2d Sess., 114 (October 10, 1978) (hereinafter cited as Conference Report). Nevertheless, the rule proposed herein applies only to those establishments (other than new boilers) that have demonstrated some reliance on alternative fuel. It seems unlikely that continued reliance on such fuel would significantly increase food costs. If it would, the relevant information is in the hands of individual users, who can apply for adjustments under Section 502(c).

[16] *Id.*

[17] *Id.*

[18] *See, e.g.*, Texas Eastern Transmission Corporation (North Alabama Gas District) Docket No. RP74-39-8, order of February 28, 1975.

[19] *Energy Data Report*, monthly report, Cost and Quality of Fuels for Electric Utility Plants, FPC Form No 423, March, 1979, at pages iii and v.

[20] *Id* at iii.

[21] *See DOE Monthly Energy Review*, July 1979, at 88.

Note.—Low sulfur prices were estimated based on the simple average of retail prices shown for residual fuel oil with less than 1 percent sulfur content.

[22] In the proposed rule the term "boilers" does not include combustion turbines and diesels, since the alternative fuel for those facilities is usually No. 2 fuel oil, which in the Commission's present view is not reasonably available at present and for which we lack the basis to project reasonable availability for the forthcoming heating season.

¶ 32,037 High Cost Natural Gas Produced From Tight Formations

44 F.R. 52253 (September 7, 1979).

[18 CFR Parts 271 and 274]

[Docket No. RM79-76]

High Cost Natural Gas Produced From Tight Formations; Proposed Rulemaking and Public Hearings

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking and public hearings

SUMMARY: The Commission is considering promulgating a regulation regarding non-associated natural gas produced from tight formations in order to promote production of such gas through use of incentive pricing. The proposed regulation establishes which gas will qualify for the incentive prices, the price to be charged for such gas, and the procedures for qualifying gas for the incentive price. The Commission intends to hold public hearings on this proposed rule in Washington, D.C. and Denver, Colorado.

DATES: Written comments on Docket No. RM79-76 to be received by October 15, 1979. Public hearings September 24, 1979 in Washington, D.C. and September 27, 1979 in Denver, Colorado at locations to be announced. Requests to participate in public hearings to be received in the Office of the Secretary no later than 7 days prior to the hearing.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Philip Yates, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4308-D, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8078.

OR

Wayne Thompson, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, Room 6106-A, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-4562.

OR

Victor Zabel, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, Room 6100-C, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-4568.

Issued: August 29, 1979.

I. Background

The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations in order to implement sections 107(b) and 107(c)(5) of the Natural Gas Policy Act of 1978, 15 U.S.C. 301, *et seq.*, (NGPA) as they relate to non-associated natural gas produced from tight formations. Sections 107(b) and 107(c)(5) of the NGPA allow the Commission to set "reasonable" incentive prices for natural gas "produced under such . . . conditions as the Commission determines to present extraordinary risks or costs."

"Tight formation" gas is non-associated natural gas produced from geological formations of low permeability. In order to produce natural gas in economical quantities from such formations, certain enhanced production techniques must be applied in order to create fractures to enhance the flow of gas. At present, only hydraulic fracturing and explosive fracturing have been proven to be commercially practical, although other techniques may be developed in the future.

A Notice of Inquiry was issued on June 13, 1979, in Docket No. RM79-44, requesting comments on sections 107(b) and 107(c)(5). Of the many comments that were received, only a few mentioned natural gas produced from tight formations. The Commission anticipates that many more comments on tight formations will be elicited by this notice of proposed rulemaking. However, Congress has already recognized that gas production from

tight formations entails "extraordinary" costs within the meaning of section 107(c)(5). See Joint Explanatory Statement of the Committee on Conference, H.R. Rep. No. 95–1752, 95th Cong., 2d. Sess. 87 (1978). In addition, the President indicated in his recently announced energy program that production from tight formations is essential to meet the nation's energy needs. The Secretary of Energy, in a letter to the Commission dated July 21, 1979, also emphasized the need to expeditiously promulgate rules providing a reasonable incentive price for gas produced from tight formations. This regulation is now being proposed in response to that need.

II. Summary of the Proposed Rule

The regulation here proposed establishes which natural gas will qualify under section 107 because produced from a tight formation, which procedures the Commission will follow in determining whether a formation is a tight formation, the filing requirements for seeking a determination under Part 274 that gas is produced from a well which produces tight formation gas and the incentive price to be charged for such gas.

The Commission proposes to establish which natural gas produced from tight formations will qualify for the section 107 incentive price by specifying what formations or portions of formations should qualify as tight formations and establishing the criteria under which a particular well drilled into such formations will qualify for the section 107 incentive price.

The Commission is proposing to define tight formation gas based on the known or estimated characteristics of the particular formation or portion thereof from which the gas is produced and on certain easily ascertainable characteristics for the well rather than upon the well's specific producing characteristics. The Commission proposes to adopt this methodology because it would be difficult to define tight formation gas by exclusive reference to specific producing characteristics of a well and the burdens of such a requirement might operate to discourage drilling into tight formations. Were a production test to be adopted, testing would be required for each well and, because it is difficult to estimate *in situ* gas permeability based on core analysis, extensive and expensive pressure build-up analysis would be required to determine each well's true production characteristics.

Although many geological formations have been considered to be tight formations, most geologists agree that a majority of the geological indicia, such as permeability, porosity, net pay thickness, etc., vary widely from formation to formation and from area to area within the same formation. However, tight formations are generally characterized by low gas permeability, resulting in low rates of production which can be substantially increased through the use of enhanced recovery techniques such as fracturing. Therefore, the commission is proposing to consider as tight formations those formations or portions thereof which have low production rates due to low gas permeability and for which an appropriate tight formation enhanced recovery technique is available.

An appropriate technique is one which is expected to increase substantially the rate of natural gas production which could be achieved without use of the technique. Such a technique must also be substantially more expensive than those techniques used for a typical well which does not produce from a tight formation. Because different formations may require different techniques, the Commission proposes to determine the appropriate techniques for each particular designated tight formation. The Commission has tentatively identified certain specific tight formations in the proposed rule, but has not specified appropriate techniques for those tight formations. However, in addition to seeking comments on the tight formations listed in the proposed rule the Commission is also soliciting comments as to which techniques would be appropriate for increasing gas production from those formations.

The Commission seeks to establish an incentive price that will lead to the development of areas with low deliverability that would not be expected to be developed in the absence of an incentive price because of the high cost of production. In addition to proposing certain areas as tight formations the Commission is also proposing four general guidelines for qualifying an area as a "tight formation": (1) The formation or portion thereof must have an estimated average *in situ* gas permeability, throughout the pay section, of .03 millidarcies [1] or less; (2) A well drilled into the formation or portion thereof must be *expected* to produce, with no production stimulation, an average of 200 Mcf or less per day, (3) Production from such a well must be *expected* to be increased substantially after the completion of an appropriate technique; and (4) No field rules for development of the formation or portion thereof can have been established by or requested of a jurisdictional agency.

The Commission Staff has preliminarily identified the following formations all or portions of which may qualify under the guidelines:

Basin	Formation
Greater Green River	Fort Union. Almond A, or B, Erickson, Rock Springs/Blair, other Mesa Verde.
Piceance	Fort Union, Corcoran-Cozette, other Mesa Verde.
Uinta	Wasatch, Barren, Coaly, Castlegate.
Northern Great Plains and Williston	Judith River, Eagle, Carlisle, Greenhorn/Frontier.
Big Horn	Mesa Verde.
Douglas Creek Arch	Mancos, Dakota.
Sonora	Canyon.
Cotton Valley Sweet	Cotton Valley and Gilmer Lime.
Denver	Niobrara, Sussex, Dakota.
Ouachita	Stanley.
San Juan	Dakota.
Wind River	Frontier, Muddy.
East Texas	Bossier, Cotton Valley Sandstone, Haynesville, Smackover.

The list is neither exhaustive nor conclusive as to eligibility. It merely reflects what the Staff currently believes may be examples of qualifying tight formations. The Commission is soliciting comments on the listed formations as well as the guidelines for identifying such formations. Those comments which suggest that a particular area not be included in the list must indicate which of the guidelines it fails to meet and support such allegations with the information required under § 271.705. Those comments which recommend that a listed formation or additional formations be included in the list must establish that the formation meets the guidelines based on the information required under § 271.705.

Section 271.705 requires that a recommendation include geographical and geological descriptions of the formation or portion of the formation which is recommended for classification as a tight formation; geological and engineering data to support the recommendation and the source of that data; the number and location of all wells which produce or have produced natural gas from the recommended tight formation; the types and extent of appropriate techniques which are expected to be necessary to increase production from a well producing from the recommended tight formation and the expenditures necessary for employing those techniques; the degree of increase in production to be expected from use of such techniques and engineering and geological data to support that estimate; information indicating that no field rules for development of the formation or portion thereof have been established by or requested of a jurisdictional agency; and any other information which the applicant deems relevant.

The Commission will look to the comments submitted on the proposed list of tight formations for evidence as to whether the formations currently proposed meet the guidelines for defining a tight formation set forth in

[1] A "darcy" is a unit for measuring permeability.

§ 271.703(b)(5) and will decide whether to include a formation in the list issued in the final rule based on those comments. The Commission also intends to provide an opportunity for comment on any formations which it may add to the list. The Commission anticipates that many recommendations will be submitted by jurisdictioinal agencies. Because it recognizes that such agencies are especially familiar with the geological and production characteristics of particular formations, the Commission will solicit and give special attention to any recommendations or comments from those agencies.

Once the Commission has determined that the area into which a well has been drilled qualifies as a tight formation, the well must meet three additional criteria before gas produced from it may qualify for the incentive price: (1) The well must have been spudded on or after the date upon which this proposed rule was voted on by the Commission, i.e., August 17, 1979; (2) The well must qualify under Subpart C of Part 271 as a new, onshore production well; and (3) The well must have been subject to a technique which the Commission has identified as a technique which requires extraordinary expenditures and which must be employed in order to increase substantially the production from that tight formation.

The Commission is proposing these three criteria in order to encourage additional gas production while avoiding the drilling of unnecessary wells. Thus, no well drilled into a reservoir which can be effectively and efficiently drained by an old well can qualify as a tight formation well under this proposed rule. In addition, the Commission believes that use of an appropriate technique should be a condition precedent for qualifying a well as a tight formation well, because the incentive price is intended to encourage producers to undertake the costs of employing such techniques.

The proposed regulation is intended to provide price certainty based on reasonable geological *expectations*. The designation of a tight formation will be based on geological evaluations founded upon the best information available. Once the Commission has designated an area as a tight formation, any well completed in the formation will qualify for the incentive price so long as the well itself meets the three additional criteria. The actual production figures of a well would be irrelevant. If fracturing does not substantially increase a qualifying well's production, that fact would also be irrelevant so long as the technique used has been designated by the Commission as an appropriate technique for the tight formation.

In addition to designating what gas will qualify under section 107(c)(5) of the NGPA, the Commission is also authorized under section 107(b) to set a "reasonable" incentive price for section 107(c)(5) gas. The Secretary of Energy has requested that the maximum lawful price for tight formation gas be related to the price of "deregulated oil" because the increased natural gas production will compete with refined oil products. The Commission believes that price comparability requires that the wellhead price for tight formation gas be referenced to the price of crude oil rather than residual fuel oil because both this gas and crude oil are subject to additional costs of rough equivalence before they are delivered to the end user. However, the Commission is seeking comments on whether the price of tight formation gas should be indexed to the price of crude oil or residual fuel oil.

The world price of Saudi Arabian benchmark crude oil is $18.00 a barrel,[2] which is equivalent to $3.1035 per MMBtu.[3] The Commission proposes to set the incentive price for section 107(c)(5) tight formation gas at 150 percent of the section 103 price ($2.079 [4] per MMBtu × 150% = 3.1185). Because the section 103 price includes an adjustment

[2] This figure is based upon the latest figures supplied by the Department of Energy Weekly Petroleum Status Report, August 10, 1979.

[3] Using a conversion factor of 5.8.

[4] The August maximum lawful price for section 103 gas.

for inflation, the maximum lawful price for section 107(c)(5) tight formation gas will in all likelihood escalate over time. However, such escalations will be keyed to the monthly inflation adjustment factor prescribed by the NGPA rather than to increases in the world price for oil. The Commission believes that this pricing mechanism will provide sufficient price predictability and will keep the price for section 107(c)(5) tight formation gas even with inflation.

The Commission specifically invites comment on the issue of deregulation of section 107(c)(5) tight formation gas. The definition for tight formation wells incorporates the criteria for section 103 wells; thus tight formation wells are also section 103 wells. Under section 121 of the NGPA certain section 103 wells become deregulated in 1985, others in 1987. Section 101(b)(5) of the NGPA provides that, if gas qualifies for a maximum lawful price under more than one provision, "the provision which could result in the highest price shall be applicable." The Commission is soliciting comments as to whether section 101(b)(5) requires that tight formation wells become deregulated either in 1985 or 1987 if the *deregulated* price for section 103 gas will be higher than the regulated price for tight formation gas.

III. Public Procedure

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79-76. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, October 15, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

B. Public Hearings

Public hearings on this proposed rule will be held on September 27 in Denver, Colorado, and on September 24 at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. The exact locations will be announced prior to September 5, 1979, by notice published in the **Federal Register**. Interested persons may also obtain this information by calling the Office of the Secretary of the Commission.

Requests to participate in either of the hearings should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than seven days prior to the hearing. Requests should reference Docket No. RM79-76, and should indicate in which hearing the person wishes to participate, the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in each hearing will be available in the Commission's Office of Public Information three days before the hearing and will be available at the site of the hearing on the morning it is convened.

The hearings will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearings. Transcripts of the hearings will be available in the public file for this proceeding, Docket No. RM79-76, in the Commission's Office of Public Information.

(Natural Gas Act as amended, 15 U.S.C. 717 *et seq.*; the Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.*; the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; EO 12009, 42 FR 46267)

Based on the foregoing, the Commission proposes to amend Parts 271 and 274 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Part 271 is amended in the Table of Contents under Subpart G by deleting the item "271.703 Definition of deep, high-cost natural gas" and inserting in lieu thereof the item "271.703 Definitions" and is further amended by adding an item after item 271.704 to read as follows: "271.705 recommendations regarding tight formations."

2. Subpart G of Part 271 is amended in §§ 271.701, 271.702 and 271.703 to read as follows:

§ 271.701 Applicability.

This subpart implements section 107 of the NGPA and applies to the first sale of natural gas which a jurisdictional agency determines is deep, high-cost natural gas or high-cost natural gas produced from a tight formation.

§ 271.702 Maximum lawful price.

(a) The maximum lawful price, per MMBtu, for deep, high-cost natural gas shall be the price specified for Subpart G of Part 271 in Table I of § 271.101(a).

(b) The maximum lawful price, per MMBtu, for high-cost natural gas produced from tight formations shall be equal to 150 percent of the maximum lawful price specified for Subpart C of Part 271 in Table I of § 271.101(a).

§ 271.703 Definitions.

For purposes fo this subpart the following definitions apply.

(a) Deep, high-cost natural gas is natural gas which a jurisdictional agency determines, in accordance with Parts 274 and 275, is produced:

(1) From any well, the surface drilling of which began on or after February 19, 1977; and

(2) From a completion location which is located at a depth of more than 15,000 feet.

(b) High-cost natural gas produced from a tight formation is natural gas which a jurisdictional agency has determined, in accordance with Parts 274 and 275, is non-associated natural gas produced from any well:

(1) The surface drilling of which began on or after August 17, 1979;

(2) Which qualifies as a new, onshore production well as defined in § 271.303;

(3) Which has been subject to an appropriate technique as defined in paragraph (c) of this section; and

(4) Which has been drilled into one of the following tight formations:

(i) The following designated tight formations:

Basin	Formation	Appropriate technique
Greater Green River	Fort Union	
	Almond A, or B, Erickson, Rock Springs/Blair, other Mesa Verde.	
Piceance	Fort Union, Corcoran-Cozette, other Mesa Verde.	
Uinta	Wasatch, Barren, Cosly, Castlegate.	
Northern Great Plains and Williston.	Judith River, Eagle, Carlisle, Greenhorn/Frontier.	
Big Horn	Mesa Verde	
Douglas Creek Arch	Mancos, Dakota	
Sonora	Canyon	
Cotton Valley Sweet	Cotton Valley and Gilmer lime.	
Denver	Niobrara, Sussex, Dakota.	
Ouachita	Stanley	
San Juan	Dakota	
Wind River	Frontier, Muddy	
East Texas	Bossier, Cotton Valley Sandstone, Haynesville, Smackover.	

(ii) Any other area of low deliverability that would not be expected to be developed in the absence of an incentive price because of the high costs of production and which the Commission has determined is a tight formation based upon the following guidelines:

(I) The formation must have an estimated average *in situ* gas permeability, throughout the pay section, of .03 millidarcies or less;

(II) A well drilled into the formation must be expected to produce, with no production stimulation, an average of 200 Mcf or less per day;

(III) Production from such a well must be expected to be increased substantially after the completion of an appropriate technique; and

(IV) No field rules for development of the formation or portion thereof have been established by or requested of a jurisdictional agency.

(c) The term "appropriate technique" is any technique (applied to a particular designated tight formation) which is:

(1) Substantially more expensive than those techniques used for a typical well which is not drilled into a tight formation; and

(2) Expected to increase substantially the rate of natural gas production which could be achieved without the technique.

3. Subpart G of Part 271 is further amended by adding § 271.705 to read as follows:

§ 271.705 Recommendations regarding tight formations.

In determining which additional formations constitute tight formations (for purposes of § 271.703(b)(4)(ii)) the Commission will consider all recommendations which contain the following information:

(a) Geographical and geological descriptions of the formation or portion of the formation which is recommended for classifcation as a tight formation;

(b) Geological and engineering data to support the recommendation and the source of that data;

(c) The number and location of all wells which produce or have produced natural gas from the recommended tight formation;

(d) The types and extent of appropriate techniques which are expected to be necessary and the expenditures necessary for employing those techinques;

(e) The degree of increase in production to be expected from use of such techniques and engineering and geological data to support that estimate;

(f) Information indicating that no field rules for development of the formation or portion thereof have been established by or requested of a jurisdictional agency; and

(g) Any other information which the applicant deems relevant.

4. Section 274.205 is amended to read as follows:

§ 271.205 High-cost natural gas.

(a) *Deep, high-cost natural gas.* A person seeking a determination for purposes of Subpart G of Part 271 that natural gas is produced from a well which is a deep, high-cost well shall file an application with the jurisdictional agency which contains the following items:

(1) FERC Form No. 121,

(2) All well completion reports for which a determination is sought;

(3) Well logs or well servicing company reports or such other information which will corroborate the depth of the completion location reported in the well completion report;

(4) Directional drilling surveys if available;

(5) A statement by the applicant, under oath, that the surface drilling of the well for which he seeks a determination began on or after February 19, 1977, and that the well completion location is below a true vertical depth of 15,000 feet; and that he has no knowledge of any information not described in the application which is inconsistent with his conclusions; and

(6) If the jurisdictional agency so requires, certified copies of records relied on by the applicant, including copies of the agency's official files.

(b) *Natural gas produced from tight formations.* A person seeking a determination for purposes of Subpart G of Part 271 that natural gas is produced from a tight formation well shall file with the jurisdictional agency an application which contains the following items:

(1) All those items specified in § 274.204 except the item specified in paragraph (d)(1) of that section;

(2) A map of sufficient clarity to locate and identify the well for which a

determination is sought as being within a tight formation or portion thereof;

(3) Documentary evidence that the well has undergone an appropriate technique designated for the tight formation by the Commission; and

(4) A statement by the applicant, under oath, that the surface drilling of the well for which a determination is sought was begun on or after August 17, 1979.

¶ 32,038 Section 206(d) Exemption for New Small Boiler Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

44 F. R. 57783 (October 5, 1979)

18 CFR Part 282

[Docket No. RM79-48]

Section 206(d) Exemption for New Small Boiler Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978; Proposed Rulemaking and Public Hearing

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking and Public Hearing.

SUMMARY: The Federal Energy Regulatory Commission hereby proposes to promulgate a rule to enlarge the class of small boiler facilities that are exempt from the incremental pricing program under Title II of the Natural Gas Policy Act of 1978 (NGPA). This proposed rule would be adopted under the authority of section 206(d) of the NGPA, and would grant an exemption from the incremental pricing program to those industrial boiler fuel facilites which came into existence after November 9, 1978, or which come into existence at some time in the future, and which have a total capacity of 300 thousand cubic feet (Mcf) per day or less.

DATES:
Comments by October 29, 1979.
Requests to speak by October 15, 1979.
Hearing date: October 22, 1979.

ADDRESS: All comments and requests to speak to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washingotn, D.C. 20426 (Reference Docket No. RM79-48). Hearing location: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Issued September 28, 1979.

I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. No. 95-621) requires that interstate pipelines and local distributon companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of surcharges. These surcharges may not, however, raise the price of gas to the user above the price of fuel oil which could be used as an alternative to natural gas.

The incremental pricing program is to be implemented in two phases. The only facilities affected during the first phase will be those large industrial facilities using natural gas as fuel for boilers. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979.[1]

During the second phase of the program, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The NGPA sets May 9, 1980, as the date for the regulations implementing the second phase and establishes that those regulations will be subject to Congressional review and possible disapproval by either House.

Subsections 206 (a), (b), and (c) of the NGPA provide that small industrial boiler fuel facilities in existence on November 9, 1978, agricultural users, schools, hospitals, and certain other facilities shall be exempt from incremental pricing. In addition, to the extent provided by the Commission by rule, the use of natural gas as a boiler

[1] These regulations are contained in two dockets, Docket Nos. RM79-14 and RM79-21.

fuel by any qualifying cogeneration facility (which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978) shall be exempt from incremental pricing.

Subsection 206(a) of the NGPA requires the Commission to grant an interim exemption from incremental pricing to any industrial boiler fuel facility which was in existence on November 9, 1978, and which used no more than an average of 300 Mcf per day for any month in a base period determined appropriate by the Commission. The Commission, in the regulations relating to this interim exemption in Docket No. RM79–14, has adopted 1977 as the base period. Section 206 also sets May 9, 1980, as the date for the permanent rule which will contain certain statutorily prescribed refinements of the interim rule.

Under subsection 206(d) of the NGPA, the Commission may, by rule or order, exempt other individual industrial facilities or categories of such facilities from the incremental pricing program. Rules proposing such exemptions must be submitted to the Congress for its review prior to taking effect.

In the Notice of Proposed Rulemaking in Docket No. RM79–14, issued on June 5, 1979 (44 FR 33099, June 8, 1979), the Commission announced that it would issue a Notice of Proposed Rulemaking in Docket No. RM79–48 regarding a new small boiler exemption under subsection 206(d) of the NGPA for "new" small boilers—i.e., small boilers constructed since November 9, 1978. This was discussed at page 12 of the June 5th Notice (pp. 33100–33101 in the Federal Register). This Notice of Proposed Rulemaking and Public Hearing is the one referred to in the June 5th Notice.

The regulations in this docket would exempt from incremental pricing the gas used to small boiler facilities which came into existence after November 9, 1978, including those which come into existence at some time in the future. These facilities would be referred to as "new" facilities.

By its terms, the NGPA grants an exemption only to those "small" boiler facilties which were in existence on November 9, 1978, the date of enactment ("existing" facilities). Both the statute and the legislative history are silent as to the reason why an exemption from the incremental pricing program was granted only to existing small boiler facilities and not to new small boiler facilities. The Commission believes that, for purposes of implementing the incremental pricing program, it would be inconsistent and inequitable to distinguish between small facilities which were in existence on November 9, 1978 and those which came into existence after November 9, 1978. Therefore, the Commission proposes to enlarge the class of exempt small boiler facilities to include new small boiler facilities.

Since the regulations below are being proposed pursuant to subsection 206(d) of the NGPA, if they are adopted by the Commission as a final rule, they will be submitted to the Congress for review prior to taking effect. After the regulations are submitted to each House of Congress, they may take effect following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30 day period.

II. Discussion

A. Regulations Proposed

The effect of the proposed rule below, if adopted as a final rule, would be to enlarge the class of small boiler facilities which are exempt from the incremental pricing program. For this reason, the Commission proposes to use 300 thousand cubic feet (Mcf) as the threshold for determining "small", which is the same threshold required by section 206(a)(1) for the interim statutory exemption for existing small boiler facilities. Thus, a new facility which has a total capacity of 300 Mcf per day or less would be eligible for an exemption from the incremental pricing program.

Furthermore, the proposed regulations contain a provision which would require that, in the event the 300 Mcf threshold is lowered when the permanent exemption for existing small boilers becomes effective, the threshold for the exemption for new small boiler facilities proposed in this docket would also be lowered.

Section 206(a)(2) of the NGPA requires that, in the permanent exemption for existing small boiler facilities, the Commission shall lower the 300 Mcf threshold if necessary to assure that the use of natural gas in 1977 by exempt existing small industrial boiler fuel facilities did not exceed 5 percent of the total volume of natural gas that was transported in interstate pipelines and used as a boiler fuel in 1977.

B. Method for Determining Size of a Boiler Facility.

The most significant question that must be addressed in proposing to enlarge the class of small boiler facilities eligible for exemption from the incremental pricing program is how to determine the size of such facilities. The statutory exemption for existing small boiler facilities is calculated on a base period usage approach.

In determining how to evaluate the size of a boiler facility, no method is free of difficulties. The most obvious approach would be the use of some reference period for measuring actual gas consumption. However, under any such "base period" approach, the selection of an appropriate base period is an immediate problem. Since, by definition, a new facility would be one which has come into existence since November 9, 1978, the class of boilers which would have a full year during which gas consumption could be measured would be very small. Use of less than a full year as a base period might result in distortions due to the seasonal availability of gas on many systems and seasonal patterns of usage.

Use of a fixed based period would also be inadequate for determining the status of facilities coming into existence during the base period or at some point in the future. On the other hand, if the problem were addressed through use of a "rolling" base period, the owner of a new facility would not be able to ascertain the status of the facility until after some interval of time had elapsed.

A fixed based period approach could also provide an incentive to circumvent the intent of the new small boiler exemption. One manner of circumvention we foresee would be to hold the gas consumption of a larger than 300 Mcf facility at or below 300 Mcf per day for the duration of the reference period. Only a burdensome system of continuous monitoring would suffice to close this loophole.

Moreover, any base period approach, no matter how carefully constructed and monitored, could be circumvented to some degree. A large new boiler facility could find it economically attractive to burn exactly 300 Mcf of gas per day and satisfy the remaining fuel requirements with oil. Thus, a perverse fuel use pattern would result from the base period regulation. Economic waste would be highly likely.

The alternative to one of the base period approaches which the Commission believes has the greatest probability of success is to determine the size of a boiler facility by looking to its capacity. One problem with this approach, however, is developing a rule for relating boiler capacity to fuel use. A small boiler which operates around the clock may consume more gas than a larger boiler which operates intermittently.

Since a boiler's firing rate (nameplate rating) is stated in terms of MMBtu (million British thermal units) per hour or Mcf per hour, we have determined to make some assumptions about the fraction of rated capacity actually utilized and the number of hours a boiler is fired per day. The first assumption would appear to be best met by assuming that a boiler is operated at rated capacity. Although some boilers could be operated at a rate above or below the nameplate rating, the Commission believes that nameplate rating is the most objective, verifiable,

administratively feasible standard to use in determining a boiler's capability.

The second assumption, regarding the number of operating hours per day, is more problematic. A three shift per day operation would be a conservative assumption in that no facilities so evaluated and fund exempt by reason of small size could in fact be using more than 300 Mcf per day (except by exceeding the rated capacity of the boiler). Since not all boilers are run for three shifts every day, the "24 hour per day" assumption might result in many boiler facilities which actually consume much less than 300 Mcf per day being subject to the incremental pricing program.

Furthermore, to assume a one shift per day operation would probably also be inappropriate. Generally, it is considered inefficient to run a boiler for only 8 hours per day. The Commission therefore proposes a 16 hour period as a reasonable middle ground for determining a boiler's capacity. In effect, this approach assumes dual shift operation.

For boilers whose nameplate rating is stated in terms of Mcf per hour, we propose to multiply the rating by 16 hours per day in order to calculate the boiler's capacity. For boilers rated in terms of MMBtu per hour, we propose to convert the rating to Mcf per hour (based on a conversion factor of one MMBtu to one Mcf) before multiplication by 16.

For a facility with multiple boilers, the total capacity of the facility would be the sum of the capacities of all boilers within the facility which have the capability to burn natural gas. Any new facility with a total capacity which is the lesser of: (1) no more than 300 Mcf per day; or (2) no more than such other volume of natural gas determined by the Commission in accordance with section 206(a)(2)(B)(ii) of the NGPA would be eligible for an exemption from the incremental pricing program.

C. Obtaining the Exemption. We are proposing that a facility would obtain an exemption by filing an affidavit. The exemption would be effective until such time as the facility modified any of its boilers if the modification resulted in a change in a boiler's capacity, or until the facility was expanded by the addition of one or more boilers with gas fired capability. At such a time, the facility would be required to notify the Commission and its natural gas supplier of these changes, and the facility's continued eligibility for an exemption from the incremental pricing program would be determined. A copy of the Affidavit we propose to utilize is attached hereto.

III. Summary of The Proposed Rule

The proposed regulation would add new §§ 282.210 and 282.211 for new small boiler exemptions to Part 282 of the Commission's regulations.

The new § 282.210 would exempt small boiler facilities which came into existence after November 9, 1978, or which come into existence at some time in the future. For a facility which has more than one boiler with gas fired capability, the facility's total capacity would be the sum of the capacities for each boiler which has the capability to burn natural gas. The size of a facility would be determined by adding the nameplate rated capacity for all boilers within a facility which have the capability to use natural gas. For a boiler rated in terms of Mcf per hour, the boiler's capacity would be obtained by multiplying the rating by 16. If a boiler is rated in terms of MMBtu per hour, before being multiplied by 16, the rating would first be converted to Mcf per hour using a conversion factor of one Mcf per one MMBtu.

Any facility with a rated capacity of no more than 300 Mcf per day would be granted an exemption from the incremental pricing program. The 300 Mcf figure would be used until such time as the permanent exemption for existing small boiler facilities becomes effective. At that time, the number that would be used as the threshold for the permanent exemption would also be used for determining exemptions for new small boiler facilities under § 282.210 of the regulations.

The new § 282.211 would describe the procedures that must be followed in

order to obtain a new small boiler exemption. Suppliers would be obligated to notify the facilities which might be exempt and to mail affidavits for new small boiler facility exemptions to those facilities which request them. The other requirements for filing and processing affidavits adopted in Docket No. RM79–14 would be used for the exemptions proposed in this rule.

The affidavit that would be filed in order to obtain an exemption would contain one question, which, if answered affirmatively, would result in an exemption for new small boiler facilities.

IV. Comments Requested

The Commission requests comments on all aspects of the proposed regulations set forth below. The Commission particularly invites comments on the issues identified above and on approaches to those issues other than the ones reflected in the regulations below.

In addition, the Commission is concerned that, if this proposal is adopted as a final rule, it may provide an incentive for the construction of small boiler facilities instead of the expansion of existing facilities. Or, the rule might provide an incentive for the addition of non-gas burning boilers to increase the facility's capability. Comments are, therefore, requested on these potential problems. Comments are especially requested on the economic feasibility of: (1) expanding a facility by the addition of non-gas burning boilers in order for the facility to retain its exemption; or (2) modifying a facility by reducing its total capacity to burn natural gas as a boiler fuel in order to gain an exemption from the incremental pricing program.

V. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM79–48. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, October 29, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing.* A public hearing on this proposed rule will be held on October 22, 1979, beginning at 10: a.m. E.D.T. at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing. Interested persons may also obtain this information by calling the Office of the Secretary of the Commission.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than seven days prior to the hearing. Requests should reference Docket No. RM79–48, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Office of Public Information three days before the hearing and will be available at the site of the hearing on the morning it is convened.

The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The

presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available in the public file for this proceeding, Docket No. RM78-48, in the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, as set forth below.

By Direction of the Commission.

Lois B. Cashell,

Acting Secretary.

1. Part 282 is amended by adding new §§ 282.210 and 282.211 to read as follows:

§ 282.210 Exemptions for new small boilers under section 206(d).

(a) *General Rule.* Natural gas used for boiler fuel in a new small industrial boiler fuel facility shall be exempt from incremental pricing under this part.

(b) *Definition.* For purposes of this section, a "new small industrial boiler fuel facility" is a facility which:

(1) came into existence after November 9, 1978; and

(2) has total capacity, as determined in accordance with paragraph (c) of this section, which is no more than the lesser of: (i) 300 Mcf; or (ii) the volume of natural gas determined by the Commission in accordance with section 206(a)(2)(B)(ii) of the NGPA.

(c) *Capacity.* (1) *Definition.* The capacity of a boiler which has the capability to burn natural gas is the volume of natural gas, stated in Mcf, which would be consumed if the boiler were operated at nameplate rated capacity for a continuous 16 hour period.

(2) *Rating in terms of MMBtu.* For purposes of this section, the capacity of a boiler whose nameplate rated capacity is stated in terms of MMBtu per hour shall be obtained by converting the MMBtu rating to an Mcf equivalent. This conversion shall be based on a conversion factor of one MMBtu to one Mcf.

(3) *Total Capacity of a facility.* The total capacity of an industrial boiler fuel facility shall be the sum of the capacities of all boilers within the facility which have the capability to burn natural gas.

§ 282.211 Obtaining an exemption for a new small boiler facility.

(a) *General.* This section establishes procedures by which owners or operators of new small industrial boiler fuel facilities may obtain an exemption for natural gas used in such facilities.

(b) *Exemption by affidavit.* (1) *Commission to provide exemption affidavits.* As of (the effective date of this section), new small boiler exemption affidavits as described in paragraph (b)(3) of this section will be available to natural gas suppliers for purposes of paragraph (b)(2) of this section and to any other interested person upon request from the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(2) *Availability of exemption affidavits from natural gas suppliers.* (i) Natural gas suppliers shall notify facilities which may be eligible for an exemption under § 282.210 and shall mail a new small boiler exemption affidavit to those facilities which request one.

(ii) Natural gas suppliers shall make new small boiler exemption affidavits available at their principal place of business on an ongoing basis during regular business hours.

(3) *Contents of exemption affidavit.* The new small boiler exemption affidavit will provide the owner or operator of an industrial boiler fuel facility with an opportunity to respond to the following question: Did your facility come into existence after November 9, 1978, and does the facility, on the basis of records, documents, or data in the customer's possession, have

a total capacity which is no more than 300 Mcf per day?

Appendix A

Note.—This appendix will not appear in the Code of Federal Regulations.

Federal Energy Regulatory Commission, Washington, D.C.

Exemption From Incremental Pricing for the Use of Natural Gas in New Small Boiler Fuel Facilities

Docket No. RM79-48

Participation is Voluntary. Copies of executed exemption affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

Please Read Before Completing This Affidavit

Purpose

The Natural Gas Policy Act of 1978 (NGPA) provides that natural gas used as boiler fuel by any industrial boiler fuel facility will be subject to incremental pricing surcharges unless exempted. The statute provides for certain exemptions from these incremental pricing surcharges. The affidavit entitled "Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas" serves the purpose of identifying those uses of natural gas that are entitled to a full or partial statutory exemption.

In addition, the statute provides that the Federal Energy Regulatory Commission has the discretion to propose other exemptions from the incremental pricing program. The Commission has issued a rule which provides that new small industrial boiler fuel facilities which have come into existence since November 9, 1978, are eligible for an exemption from incremental pricing. This affidavit serves the purpose of identifying those "new" small boiler facilities which are entitled to an exemption from incremental pricing surcharges.

Notice

If you do not complete and return this affidavit or the affidavit entitled "Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas," setting forth your claim to an exemption *ALL* gas sold to your facility will be subject to incremental pricing surcharges. Additionally, if circumstances or ownership change, you should immediately notify your natural gas supplier(s) of the change so that the correct amount of surcharge may be calculated as to your gas use or, if needed, you may complete a new exemption affidavit to obtain a new or changed exemption from the incremental pricing surcharges. Failure to report changes can subject your facility to civil penalties of appropriate amounts under Section 504 of the Natural Gas Policy Act of 1978.

General Instructions

If you claim an exemption from incremental pricing surcharges for the gas used by your facility which has been identified by your natural gas supplier as a potentially non-exempt industrial boiler fuel facility, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which an exemption from incremental pricing surcharges is claimed.

The original and five copies of this affidavit should be submitted to: Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility shall retain such records, documents and data which formed the basis for the exemption claimed on this affidavit. Definitions which may be helpful in completing this affidavit are provided below.

If you have any questions concerning this affidavit, contact Ms. Alice Fernandez on (202) 275-4406.

Definitions

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.

(5) "Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the

processing or changing of raw or unfinished materials into another form or product.

(6) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(7) "Capacity" means, as to a boiler which has the capability to burn natural gas, the volume of natural gas, stated in Mcf, which would be consumed if the boiler were operated at nameplate rated capacity for a continuous 16 hour period. The capacity of a boiler whose nameplate rated capacity is stated in terms of MMBtu per hour shall be obtained by converting the MMBtu rating to an Mcf equivalent. This conversion shall be based on a conversion factor of one MMBtu to one Mcf.

(8) "Total capacity of a facility" is the sum of the capacities of all boilers within an industrial boiler fuel facility which have the capability to burn natural gas.

1.0 Name of Company or Organization: ———
* * * * *

2.0 Name of Facility: ———
* * * * *

3.0 Address: Number ——— Street ———

City/Town County State
Zip Code

* * * * *

4.0 Name of Natural Gas Supplier: ———

5.0 Did your facility come into existence after November 9, 1978, and does your facility, on the basis of records, documents or data in your possession, have a total capacity, as defined in the "Definitions" of this affidavit, which is no more than 300 Mcf per day?

(a) ☐ Yes . . . Sign and return affidavit
(b) ☐ No . . . Do not return affidavit

Dated: ———

Person completing this affidavit:

Name ———
Title ———
Phone Number ———

Subscribed and sworn to before me this
—— day of ———
Notary Public———.

¶ 32,039 Small Power Production and Cogeneration—Rates and Exemptions

44 F. R. 61190 (October 24, 1979).

8 CFR Part 292

Docket No. RM79-55]

mall Power Production and ogeneration—Rates and Exemptions

GENCY: Federal Energy Regulatory ommission.

CTION: Notice of Proposed Rulemaking

UMMARY: The proposed rules would mplement section 210 of the Public tility Regulatory Policies Act of 1978 PURPA). The rules set forth rates for he sale of electric energy between ualifying small power production and ogeneration facilities and electric tilities, and provide for the exemption f qualifying facilities from certain State nd Federal regulation. The proposed ules also provide guidelines for the nterconnection arrangements between ualifying facilities and electric utilities.

DATE: Written comments by December 1, 1979. Dates of the public hearings will be announced at a later time.

ADDRESS: All responses to reference Docket No. RM79-55, and to be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D C. 20426. Locations of the public hearings will be announced at a later time.

FOR FURTHER INFORMATION CONTACT: Adam Wenner, Executive Assistant to the Associate General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8171.

SUPPLEMENTARY INFORMATION:

Issued: October 18, 1979.

Section 210(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA) requires that the Commission prescribe rules as it determines necessary to encourage cogeneration and small power production, requiring electric utilities to offer to:

(1) Sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities, and

(2) Purchase electric energy from such facilities.

In addition, section 210(e) of PURPA requires the Commission to prescribe rules under which qualifying cogeneration and small power production facilities are exempted, in whole or in part, from the Federal Power Act, from the Public Utility Holding Company Act of 1935, and from State laws and regulations respecting the rates or respecting the financial or organizational regulation of electric utilities, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

On June 26, 1979, in Docket No. RM79-54, the Commission issued proposed rules regarding the determination of which cogeneration and small power production facilities are qualifying cogeneration facilities or qualifying small power production facilities. Such qualifying facilities are entitled to avail themselves of exemptions set forth in section 210 of PURPA, and are eligible for exemption from the incremental pricing provisions of section 206(c) of the Natural Gas Policy Act of 1978 (Order No. 49, § 282.203(e), issued September 28, 1979, 44 FR 57726).

On June 27, 1979, in Docket No. RM79-55, the Commission issued a Staff discussion paper regarding issues arising under section 210 of PURPA.[1]

[1] The Staff discussion paper in Docket No. RM79-55 concerned subjects also addressed in this proposed rulemaking. Since interested persons may submit comments in response to this rulemaking, the deadline for the filing of comments on the Staff discussion paper was not extended beyond the original deadline of August 1, 1979.

The Staff discussion paper set forth many legal and policy questions arising under section 210 of PURPA. In addition to those issues, comments received in response to the Staff discussion paper and in the public hearings held in San Francisco, Chicago, and Washington, D.C. in July, 1979 on this topic raised new questions regarding the Commission's responsibility to exercise its authority under section 210. The Commission has taken into consideration these questions and comments in developing this proposed rulemaking.

Summary

The proposed rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy from other suppliers. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data with regard to present and future costs of energy and capacity on their systems.

These rules also provide that electric utilities must furnish electric energy to qualifying facilities on a non-discriminatory basis, at a rate that is just and reasonable and in the public interest, and must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilties' own generation.

The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from rate and certain other regulations under the Federal Power Act, from the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or any other means reasonably designed to give effect to the Commission's rules.

The Commission observes that this rulemaking represents an effort to evolve concepts in a newly developing area within rigid statutory constraints. The Commission is attempting to afford broad discretion to the State regulatory authorities and nonregulated electric utilities in recognition of the variety of institutional, economic, and local circumstances which may be affected by this proposed rulemaking. In this regard, the Commission seeks the fullest range of comments on the legal authority of proposed Commission action, and on the technical and practical aspects of the proposals set forth in this rulemaking.

Section-by-Section Analysis

Subpart A—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities under Section 210 of the Public Utilities Regulatory Policies Act of 1978.

§ 292.101 Scope.

Section 292.101(a) describes the scope of Subpart A of Part 292 of the Commission's rules. Subpart A applies to sales and purchases of electric energy and capacity between qualifying cogeneration and small power production facilities and electric utilities, and actions related to such sales and purchases. Section 292.101(b) provides that the authority of this subpart does not preclude negotiated agreements between qualifying cogenerators or small power producers and electric utilities which differ from rates or terms which would otherwise be required under this subpart.

Paragraph (b)(1) reflects the Commission's view that the rate provisions of section 210 of PURPA apply only if a qualifying cogenerator or small power producer chooses to avail itself of the rights and protections set forth in that section. An agreement between an electric utility and a qualifying cogenerator or small power producer to conduct sales or purchases at rates higher or lower, or under terms or conditions different from those set forth in these rules, does not violate the Commission's rules under section 210 of PURPA. Nor would provisions of State law or regulations which provide different incentives for small power production and cogeneration (than are provided in the Commission's rules) be preempted. The Commission recognizes that the ability of a qualifying cogenerator or small power producer to negotiate with an electric utility is buttressed by the existence of the statutory rights and protections of these rules, and the right of State regulatory agencies and nonregulated electric utilities to provide further encouragement of these technologies.

If, prior to the existence of the rights and protections set forth in PURPA, a cogenerator or small power producer entered into a contractual agreement by which he received sufficient financial incentive to sell his electric output to a utility, the encouragement of cogeneration or small power production does not require that he be given additional incentives. Accordingly, paragraph (b)(2) provides that Subpart A will not affect the validity of any contract between a qualifying cogenerator of small power production facility and an electric utility. At the expiration of the contract, a cogenerator or small power producer will be able to avail himself of these rules.

§ *292.102 Definitions.*

This section contains definitions applicable to Subpart A.

Paragraph (a) provides that terms defined in PURPA have the same meaning as they have in PURPA, unless further defined in this part of the Commission's regulations.

Subparagraph (1) defines a qualifying facility as a cogeneration or small power production facility which is a qualifying facility under § 292.208 of the Commission's regulations. Those regulations implement section 201 of PURPA, and are the subject of Docket No. RM79–54.

Subparagraph (2) defines "purchase" as the purchase of electric energy or capacity from a qualifying facility by an electric utility.

Subparagraph (3) defines "sale" as the sale of electric energy or capacity by an electric utility to a qualifying facility.

Subparagraph (4) defines "system emergency" as a condition on a utility's system which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property.

Subparagraph (5) defines "rate" as any price, rate charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

Subparagraph (6) defines "avoided costs" as the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost

of fuel, and some operating and maintenance expenses. If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid.

Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility, then the rates for such a purchase will be based on the net avoided capacity and energy costs.[2]

There is considerable language in both the statute and the Conference Report, as well as the Federal Power Act, in support of the proposition that capacity payments are not only legally permitted to be required by the Commission, but also, at least in some circumstances, mandated.

The Conference Report addresses the calculation of the alternative cost standard at some length. The final paragraph of this section of the Report is the following:

> The conferees expect that the Commission, in judging whether the electric power supplied by the cogenerator or small power producer will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforceable obligation of such cogenerator or small power producer to supply firm power to the utility.[3]

The references to "additions to capacity" and to obligations "to supply firm power" (the rates for which, in this Commission's experience, always include a capacity component) lead the Commission to the conclusion that, under Section 210, capacity payments to qualifying facilities can be required under certain circumstances; and that a utility's refusal to make payments based in part on avoided capacity payments could be discriminatory.

In addition, the Commission notes that the statutory language used in the Federal Power Act uses the term "electric energy" to describe the rates for sales or resale in interstate

[2] "Net avoided costs" are the excess of the total costs of the system developed in accordance with the utility's optimum capacity expansion plan, excluding the qualifying facility, over the system's total costs (before payment to the qualifying facility) developed in accordance with the utility's optimum capacity expansion plan including the qualifying facility. This concept recognizes that the energy cost associated with a deferred or avoided unit may be different from the energy costs of the qualifying facility which permitted that deferral or avoidance. In determining an optimum capacity expansion plan, a utility must consider both capacity and energy costs in order to minimize the anticipated total system costs. In providing for payments for avoided capacity, the Commission uses the term "net avoided cost" in recognition of the fact that various types of capacity will not produce the same amount of energy, so that some change in the dispatch of generation may be necessary from the remaining plants after a planned unit is deferred and the qualifying facility's capacity is substituted along with other available capacity to produce the same amount of energy at the minimum cost. This is particularly true, for example, where the capacity factor for the qualifying facility is less than the planned capacity factor from a base load (high capacity cost—low energy cost) alternative facility which is deferred. In such a case, although adequate capacity may exist on the system due to the purchase from the qualifying facility in lieu of the deferred base load unit, additional energy costs may be incurred due to increased generation from intermediate plants to make up the difference between the planned generation from the base load plant and the lesser total energy produced by the qualifying facility. Such increased energy cost is appropriately recognized by providing for the payment to the qualifying facility of the *net* avoided costs. In this way, the ratepayers are assured of paying no more than the total costs that would have been incurred had the unit not been deferred.

[3] Conference Report on H.R. 4018, Public Utilities Regulatory Policies Act of 1978, H. Rep. No. 1750, 99, 95th Cong., 2d Sess. (1978).

commerce. Demand or capacity rates are a traditional part of such rates. The term "electric energy" is used throughout the Act to refer both to electric energy and capacity. The Commission does not find any evidence that the term "electric energy" in section 210 of PURPA was intended to refer only to fuel and operating and maintenance expenses, instead of all of the costs associated with the provision of electric service.

To interpret this phrase to include only the energy would lead to the conclusion that the rates for sales to qualifying facilities only include the energy component of the rate. It is the Commission's belief that this was not the intended result, and thus provides an additional reason to interpret the phrase electric energy to include both energy and capacity.

§ 292.103 Availability of electric utility system cost data.

In order to be able to evaluate the financial viability of a cogeneration or small power production facility, an investor needs to be able to ascertain, before construction of a facility, the expected return on a potential investment. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.105 of these rules, the rate at which a utility must purchase that output is based on the utility's avoided costs.

In order to provide data to qualifying facilities which will assist them in determining the utility's avoided costs, § 292.103(b) of the rules requires electric utilities to make available to cogenerators and small power producers data concerning the present and anticipated future costs of energy and capacity on the utility's system. The data required to be provided to determine these avoided costs will have been prepared in compliance with the Commission's rules implementing section 133 of PURPA.[4] This section will thus, for the most part, require a table presenting data already developed.

Section 133 of PURPA applies to each electric utility whose total sales of electric energy for purposes other than resale exceeded 500 million kWh during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. (The phrase "before the immediately preceding calendar year" refers to the year two years prior to the current year. For example, if an electric utility exceeded the 500 million kWh limit both during 1976 and 1979, it must comply with section 133 requirements in 1981.) Section 290.102(d) of the Commission's rules implementing section 133 of PURPA granted an extension until June 30, 1982,[5] to electric utilities covered by that section having total sales of energy for purposes other than resale of less than 1 billion kWh in each of the calendar years 1976, 1977, and 1978.

The proposed coverage under paragraph (a) of these regulations is the same as that provided pursuant to section 133 of PURPA and the Commission's rules implementing that section, with an exception provided in paragraph (c) as will be discussed.

Paragraph (b) provides that each regulated electric utility must furnish to the State regulatory authority, and maintain for public inspection, data related to the costs of energy and capacity of the electric utility's system.

[4] For example, § 290.303(h) of the Commission's rules implementing section 133 of PURPA requires such electric utilities to report marginal energy costs for each month of the reporting period and for each month of the next five years. Section 290.302(g) of these rules requires electric utilities to report the estimated cost, in dollars per kilowatt of generation, of generation units likely to be installed to meet increases in peak demand. Section 290.302(f) requires the reporting of estimates, for the next ten years of information regarding total system capacity, and capacity to be supplied by other utilities.

[5] Docket No. RM79-8, issued June 5, 1979, granted an extension until May 31, 1982, to electric utilities having total sales of electric energy for purposes other than resale of less than 1 billion kilowatt-hours in each of the calendar years 1976, 1977, and 1978. The Commission recently issued revised regulations in this docket which extended this date to June 30, 1982.

Each nonregulated electric utility must maintain such data for public inspection.

Subparagraph (1) requires each electric utility to provide the estimated avoided cost of energy on its system for various levels of purchases from qualifying facilities. The levels of purchases are to be stated in blocks of one hundered megawatts or less for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than ten percent of system peak demand for systems less than 1000 megawatts. This information is to be stated on a cents per kilowatt-hour basis, for daily and seasonal peak and off-peak periods, for the immediately preceding year, and on an estimated cents per kWh basis for the current calendar year and for each of the next five years.

Subparagraph (2) requires each electric utility to provide its schedule for the addition of capacity, planned purchases of firm energy and capacity, and planned capacity retirements for each of the next 10 years.

Subparagraph (3) requires each electric utility to provide the estimated costs at completion, on the basis of dollars per kilowatt, of planned capacity additions, including planned firm purchases.

Qualifying facilities may wish to sell energy or capacity to electric utilities which are not subject to the reporting requirements of paragraph (b). In that event, paragraph (c) provides that, upon request of a qualifying facility, an electric utility not otherwise covered by paragraph (b) must provide sufficient data to enable the cogenerator or small power producer to determine the utility's avoided costs. If such utility refuses to supply the requested data, the qualifying facility may apply to this Commission for an order requiring that the information be supplied. The Commission, in considering such applications, will take into account the burden on the utility.

A non-generating electric utility which does not own or plan to acquire generating capacity may incorporate the data provided by each of its supplying utilities in its compliance with the provisions of this section.

§ 292.104 Electric utility obligations under this subpart.

Section 210(a) of PURPA provides that the Commission shall prescribe rules requiring electric utilities to offer to purchase electric energy from qualifying facilities. The Commission interprets this provision to impose on electric utilities an obligation to purchase all electric energy and capacity made available from qualifying facilities, except during periods prescribed in § 292.105(e) and during system emergencies.

There are several circumstances in which a qualifying facility might desire that the electric utility with which it is interconnected not be the purchaser of the qualifying facility's energy and capacity, but would prefer instead that an electric utility with which the purchasing utility is interconnected make such a purchase. If, for example, the purchasing utility is a non-generating utility, its avoided costs will be the price of bulk purchased power ordinarily based on an average figure representing the average cost of energy and capacity on the supplying utility's system. As a result, the rate to the qualifying facility would be based on those average costs. If, however, the qualifying facility's output were purchased by the supplying utility, its output could replace energy supplied by specific peaking units, and its capacity might enable the supplying utility to avoid the addition of new capacity. The costs, and thus the avoided costs, of peaking energy and new capacity are generally greater than system average figures.

Under these proposed rules, certain small electric utilities are not required to provide system cost data, except upon request of a qualifying facility. If, with the consent of the qualifying facility, a small electric utility chooses to transmit energy from the qualifying facility to a second electric utility, the small utility can avoid the otherwise applicable requirements that it provide the system cost data for the qualifying facility and that it purchase the energy itself.

Accordingly, paragraph (d) provides that a utility which receives energy or capacity from a qualifying facility may, with the consent of the qualifying facility, transmit such energy to another electric utility. However, if the first utility does not transmit the purchased energy or capacity, it retains the purchase obligation. Any electric utility to which such energy or capacity is delivered must purchase this energy under the obligations set forth in these rules as if the purchase were made directly from the qualifying facility.[6]

The costs of transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility.

These costs are part of the costs of interconnection, and are the responsibility of the qualifying facility under § 292.108 of these rules. However, pursuant to agreement between the qualifying facility and any electric utility which transmits electric energy on behalf of the qualifying facility, the transmitting utility may share the costs of transmission. The electric utility to which the electric energy is transmitted has the obligation to purchase the energy at a rate which reflects the costs that it can avoid as a result of making such a purchase.

Paragraph (b) sets forth the statutory requirement of section 210(a) of PURPA that electric utilities offer to sell electric energy to qualifying facilities. This section creates a Federal right for qualifying facilities to obtain electric service, in addition to any service the electric utility is obligated to provide under State laws.

The Staff discussion paper dealt with the issue of whether there is inherent in section 210 of PURPA the authority to order interconnections between electric utilities and qualifying facilities, or whether qualifying facilities must use the procedures set forth in the new sections 210 and 212 of the Federal Power Act to gain interconnection.[7] The Commission believes that the requirement to interconnect is within the legal authority of the Commission under section 210 of PURPA, particularly subsumed within the requirement to buy and sell. To hold otherwise would mean that Congress intended to have qualifying facilities go through an extended and expensive proceeding simply to gain interconnection, contrary to the entire thrust of sections 201 and 210 of PURPA.

These sections evince the clear Congressional intent to encourage development of these desirable forms of generation, and to have the commercial development of these facilities proceed expeditiously. In other words, Congress has already made the judgment that these kinds of facilities serve one of the purposes of the Act as set out in section 101, *viz*, "the optimization of the efficiency of use of facilities and resources by electric utilities", and it would be both redundant and unduly burdensome to have the sponsors of individual facilities show in an evidentiary hearing conducted under section 210 of the Federal Power Act that their project in particular would serve this end (or one of the other related goals established as criteria for an interconnection order in section 210(c)(2)). The purpose of an interconnection application, whether under section 202 or 210 of the FPA, is to secure service, whether emergency or otherwise; and section 210 of PURPA establishes the entitlement of a qualifying facility to service from the interconnected utility. In effect, the proponents of the view that a qualifying facility must apply under sections 210 and 212 of the FPA have the burden of showing that Congress intended interconnection and the entitlement to buy and sell be denied to a qualifying facility which is unable to make the

[6] The Commission notes that while a purchase from a qualifying facility may have value as energy and capacity, what is actually transmitted to the second utility is properly described as electric energy. The utility to which energy is transmitted, however, must pay rates based on energy and capacity value.

[7] Staff discussion paper, *supra*., at 10-14.

showings required by those sections, especially in light of the fact that a previously interconnected customer installing qualifying facilities would not have to so apply.

This is not to say that all of the protections that Congress has given the target of an interconnection application in sections 210 and 212 of the FPA are necessarily absent from section 210 of PURPA. The Conference Report on section 210 states that customers of utilities are not to be compelled to subsidize qualifying facilities, and this principle would seem to bear on the question of who pays the costs of interconnection as well as on the per-unit price to be paid for energy. On the other hand, the Conference Report includes a proscription against "unreasonable rate structure impediments, such as unreasonable hook up charges." This provides another argument in favor of reading section 210 of PURPA as including interconnection authority, since the elaborate cost determination required under sections 210 and 212 of the FPA is redundant if the costs of interconnection are viewed simply as a feature of the rate structure with the charge therefor based on the cost of the utility. However, the Commission does view section 210 of the FPA as an alternate avenue for remedy available to any qualifying facility which wishes to apply under it.

The obligation to interconnect can be part of either an electric utility's option to purchase from or sell to a qualifying facility. With regard to the obligation to sell, State law ordinarily sets out the obligation of an electric utility to provide service to customers located within its service area. The Commission believes that State law will normally impose on an electric utility the obligation to interconnect and that the Commission's proposal will not, in most instances, impose any additional obligation on electric utilities.

As noted in the Staff discussion paper, by installing certain equipment, an electric utility can be protected from disruption of its operations caused by a qualifying facility. The Commission has not received comments which disagree with this understanding. Therefore, through the allocation of the costs associated with such equipment to the qualifying facilities, as provided in § 292.109, and through the imposition of standards for operating reliability under § 292.110, appropriate physical and financial protection for the electric utilities is provided in the Commission's proposed rules.

Several commentors urged that the Commission require electric utilities to offer to operate in parallel with a qualifying facility. By operating in parallel, a qualifying facility is enabled automatically to export any electric energy which is not consumed by its own load. Therefore, provided that the qualifying facility complies with the standards set forth in § 292.110 regarding operating reliability, the Commission proposes in paragraph (e) that electric utilities be required to offer to operate in parallel with a qualifying facility.

§ 292.105 Rates for purchases.

Section 210(b) of PURPA provides that in requiring any electric utility to purchase electric energy from a qualifying facility, the Commission must insure that the rates for such purchases be just and reasonable to the electric consumers of the purchasing utility, in the public interest, nondiscriminatory to qualifying facilities, and that they not exceed the incremental costs of alternative electric energy (the costs of energy, which, but for the purchase, the utility would generate from another source).

Types of Purchases

In impelementing this statutory standard, it is helpful to review industry practice respecting sales between utilities. Sales of electric power are ordinarily classified as either firm sales, where the seller provides power at the customer's request, or non-firm power sales, where the seller and not the buyer

makes the decision whether or not power is to be available. Rates for firm power purchases include payments for the cost of fuel and operating expenses, and also for the fixed costs associated with the construction of generating units needed to provide power at the purchaser's discretion. The degree of certainty of deliverability required to constitute "firm power" can ordinarily be obtained only if a utility has several generating units and adequate reserve capacity. The capacity payment, or demand charge, will reflect the cost of the utility's generating units and the associated costs of assuring that firm power will be available on demand.

In contrast, the ability to provide electric power at the selling utility's discretion imposes no requirement for the construction of capacity on the seller. In order to provide power to customers at the seller's discretion, the selling utility needs only to provide for the cost of operating its generating units. These costs, called "energy" costs, ordinarily are the ones associated with non-firm sales of power.

Purchases of power from qualifying facilities will fall somewhere on the continuum between these two types of electric service. Thus, for example, wind machines that furnish power only when wind velocity exceeds twelve miles per hour may be so uncertain in availability of output as only to permit a utility to avoid generating an equivalent amount of energy. The utility must continue to provide capacity that is available to meet the needs of its customers. Rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy (system lambda), and not based on avoided capacity.

On the other hand, photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.

A facility burning municipal waste or biomass can operate more predictably and reliably than solar or wind systems. It can schedule its outages during times when demand on the utility's system is low. If such a unit demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and the capacity costs.

In order to be able to defer or cancel the construction of new generating units, a utility must obtain a commitment, sufficiently ahead of the lead time for the construction of its own new capacity, that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available. If a qualifying facility makes such a commitment, the Commission believes that, as a matter of both policy and interpretation of section 210, the qualifying facility is entitled to receive rates based on the utility's avoided costs resulting from the capacity the qualifying facility supplies. Moreover, if a cogenerator or small power producer were permitted to receive only the energy (fuel, and operating and maintenance) expenses which the purchasing utility can avoid—while the cogenerator or small power producer must himself invest in new, and often highly capital-intensive, machinery—these potential sources of energy may go undeveloped. In light of the Commission's statutory obligation to encourage cogeneration and small power production, the Commission believe that a proper interpretation of "the incremental costs of alternative electric energy" requires that, when purchases of energy can substitute for intermediate, or base-load, the rate to

the cogenerator or small power producer include the net avoided capacity and energy costs.

If a qualifying facility opts to receive rates based on avoided energy costs, such rates should reflect the energy costs of the electric utility's units which otherwise would have been operated. The Commission believes that there are a variety of acceptable ways to carry out this policy at the State level. The general concept here is that rates for purchases from the qualifying facility would be based on the highest energy cost unit then operating. The qualifying facility would continue to be dispatched until the cost of energy from the utility's generating unit with the highest energy costs is lower than the price at which the qualifying facility wishes to sell.

The Commission neither expects nor requires that the determination of utilities' avoided costs will be so precise. By definition, these costs are based on estimates of costs which would be incurred if certain events were to take place. Electric rates are ordinarily calculated on the basis of averaging. So long as a rate for purchases reasonably accounts for the avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as implementing these rules.

Paragraph (a) therefore provides that the statutory requirements regarding rates for purchases of energy and capacity from a qualifying facility are satisfied if the rate reflects the avoided costs resulting from such a purchase as determined on the basis of the cost of energy and capacity set forth pursuant to § 292.103(b) or (c).

Method of Implementation

The Commission is required under section 210 of PURPA to prescribe rules requiring electric utilities to offer to sell electric energy to and purchase electric energy from qualifying facilities. Paragraphs (b) and (c) of section 210 set forth the standards regarding the rate at which such purchases and sales shall be made. The implementation of Commission rules promulgating these standards is reserved to the State regulatory authorities and non-regulated utilities, which are required under section 210(f) to implement the Commission's rules.

One major area of concern expressed in comments received from electric utilities, cogenerators and small power producers, and State regulatory authorities has been that the Commission's rules should state general principles sufficient to leave the states and non-regulated utilities flexibility.* The basis for this recommendation is the need for experimentation in a new technological area and in an area that is subject to a variety of State procedures, the diverse nature of cogeneration and small power production systems, and the differences in the costs of energy and capacity on individual electric systems. As a result, while we herein propose that, for example, capacity costs must be paid if a utility can actually avoid the construction or purchase of capacity, our rules will not dictate the method by which such a payment is to be determined. Rather the Commission proposes to leave the selection of a methodology to the States and nonregulated electric utilities, with the understanding that should a State or nonregulated utility not fulfill the intent and purposes of our rules and of section 210 of PURPA, the Commission and others have available the enforcement power set forth in section 210(h) of PURPA to assure compliance. Additionally, the Commission is authorized to revise these rules in the future to provide greater specificity to these rules if that is necessary.

Paragraph (b) requires electric utilities, on request of a qualifying facility, to promulgate a tariff or other method for establishing rates for

*Comments of American Electric Power, filed August 1, 1979, at 2-3; Comments of Electric Consumer Resource Council (ELCON), filed August 1, 1979, at 6; Comments of the National Association of Regulatory Utility Commissioners (NARUC), filed August 1, 1979, at 2-5.

purchases from qualifying facilities of ten kilowatts or less. In Docket No. RM79-54 the Commission proposed a minimum size limitation for qualifying facilities of ten kilowatts. However, comments received in response to that proposed rulemaking indicate that such a limitation could hamper the development of auxiliary solar and wind power units. Without finally determining that question in this rulemaking, it appears to the Commission that the burden of interconnected operation on both utilities and qualifying facilities can be minimized if standard tariffs are used.

Some utilities already have such tariffs in effect. For units of ten kilowatts or less, it is likely that few changes in the utility's distribution system would be required. For example, an electric utility might offer to permit certain customers to reverse their electric meters, thus permitting consumption by the customer. While the Commission will deal more extensively with the matter of a size limitation for qualifying facilities in its final rule in Docket No. RM79-54, the Commission solicits comment here on the merits of requiring utilities to promulgate tariffs for qualifying facilities of ten kilowatts of less.

Paragraph (c) concerns a problem arising in the implementation of the concept of avoided costs. At the time that a qualifying facility delivers electric energy to an electric utility, that utility can determine its system lambda and thus calculate the costs it can avoid by making the purchase. Subparagraph (1) therefore provides rates for purchases made on an "as available" basis may be based on the purchasing utility's avoided energy costs.

In order to establish certainity of future revenue, a qualifying facility might seek to obtain a contract from a utility providing that the utility will pay a certain price for energy from a qualifying facility, under specified terms and conditions. Indeed, a qualifying facility desiring to obtain capacity credit must provide the purchasing utility with assurance that such capacity will continue to be available.

In the case of future purchases pursuant to a legally enforceable obligation, the utility's avoided energy or capacity costs may be based on the costs of production facilities which are not built and for which the only available cost data are estimates. When the qualifying facility actually supplies electricy, the utility's avoided costs may deviate from these estimated figures. The Commission believes that these potential deviations are a normal result of risk allocation resulting from contractual commitments or other legal obligations, and believes that they must be permitted if the Commission is to fulfill its mandate to encourage cogeneration and small power production. Accordingly, subparagraph (2) provides that rates for such purchases may be based on future estimated utility costs of energy or capacity regardless of whether these estimated costs actually track the actual costs that are incurred.

Paragraph (d) sets forth factors on the basis of which the State regulatory authority or nonregulated utility should determine a utility's avoided costs. These principles relate both to the quality of power available from the qualifying facility and its ability to displace or replace energy and capacity on the utility's system.

Subparagraph (1) deals with the availability of capacity from a qualifying facility during system daily and seasonal peak periods. If a qualifying facility can provide energy to a utility during peak periods when the electric utility is running its most expensive generating units, this energy has a higher value to the utility than energy supplied during offpeak periods during which only units with lower running costs are operating. Ideally, the rates for purchases would reflect the cost in the purchasing utility's system at the precise moment when such energy is supplied. The metering equipment that would be required to ascertain these times of delivery with the requisite specificity

may be either unavailable or prohibitively expensive. To the extent that such metering equipment is available, however, the State or nonregulated utility should take into account the time at which the purchase from a qualifying facility is made.

Clauses (i), (ii), (iii), (iv), and (v) deal with the reliability of a qualifying facility. When an electric utility provides power from its own generating units or from those of another electric utility, it normally controls the production of such power from a central location. The ability to so control power production enhances a utility's ability to respond to changes in demand and thereby enhances the value of that power to the utility. A qualifying facility may be able to enter into an arrangement with the utility which gives the utility the advantage of dispatching the facility.[9]

Clause (ii) refers to a qualifying facility's ability and willingness to provide power and energy during system emergencies. Section 292.109 of these proposed regulations concerns the provision of electric services during system emergencies. It provides that, to the extent that a qualifying facility is willing to forego its own use of energy during system emergencies and provide power to a utility's system, the rate for purchases from the qualifying facility should reflect the value of that service. Small power production and cogeneration facilities could provide significant back-up capability to electric systems during emergencies. One benefit of the encouragement of interconnected cogeneration and small power production may be to increase overall system reliability during such emergency conditions. Any such benefit should be reflected in the rate for purchases from such qualifying facilities.

Clause (iii) deals with periods during which a qualifying facility is unable to provide power. Electric utilities schedule maintenance outages for their own generating units at periods during which demand is low. If a qualifying facility can similarly schedule its maintenance outages during periods of low demand, or during periods in which a utility's capacity will be adequate to handle existing demand, it will enable the utility to avoid the necessity to provide redundant capacity. With regard to forced or unscheduled outages, addressed in clause (iv), it is clear that a utility cannot avoid the construction or purchase of capacity if it is likely that the qualifying facility which would replace such capacity may go out of service during the period when the utility needs its power to meet demand. Based on estimated and demonstrated reliability of the qualifying facility, the rate for purchases from a qualifying facility should be adjusted to reflect its forced and scheduled outage rate.

Subclause (v) refers to the lenght of time during which the qualifying facility has contractually or otherwise guaranteed that it will supply energy or capacity to the electric utility. A utility-owned generating unit normally will supply power for the life of the plant, or until it is replaced by more efficient capacity. In contrast, a cogeneration or small power production unit might cease to produce power as a result of changes in the industry or in the industrial processes utilized. Accordingly, the value of service from the qualifying facility to the electric utility will be affected by the degree to which the qualifying facility contractually insures that it will continue to provide power. In order to provide capacity value to an electric utility a qualifying facility need not necessarily agree to provide power for the life of the plant. A utility's generation expansion plans normally include temporary purchases of firm power from other utilities in years preceeding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into

[9] See comments of Hawaiian Electric Company, filed July 27, 1979, at 2.

a bulk power purchase arrangement with another utility. The rate for such a purchase should thus be based on the price that such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.

Subparagraph (2) concerns the relationship of energy or capacity from a qualifying facility to the purchasing electric utility's need for such energy or capacity. If an electric utility has sufficient capacity to meet its demands and is not planning to add any new capacity to its system, then the availability of capacity from qualifying facilities will not immediately enable the utility to avoid any capacity costs.[10] This is not to say that electric utilities with systems which have excess capacity need not make purchases from qualifying facilities; qualifying facilities may obtain payment for the avoided energy costs on a purchasing utility's system. Utility systems with excess capacity normally have intermediate or peaking units which use fossil fuel. As a result, during peak hours the energy costs on the systems are high, and thus the rate to a qualifying utility from which the electric utility purchases energy should similarly be high. In addition, an electric utility system with excess capacity may nevertheless plan to add new, more efficient capacity to its system. If purchases from qualifying facilities enable a utility to defer or avoid these new planned capacity additions the rate for such purchases should reflect the avoided costs of these additions.

Clause (i) of subparagraph (2) refers to the aggregate capability of capacity from qualifying facilities to displace existing or planned utility capacity. In some instances, the small amounts of capacity provided from qualifying facilities taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions or purchases. The aggregate capability of such purchases, may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively reflect the equivalent of firm power. The States and nonregulated utilities should attempt to devise rate mechanisms which will appropriately compensate qualifying facilities whose aggregate capacity enables the purchasing utility to defer or avoid capacity additions.

Clause (ii) refers to the fact that the lead time associated with the addition of capacity from qualifying facilities may be less than the lead time that would have been required if the purchasing utility had constructed its own generating unit. Such reduced lead time might produce savings in the utility's total power production cost.

Subparagraph (3) addresses the cost of savings resulting from line losses. In determining an appropriate rate for purchases from a qualifying facility the rate should reflect the cost savings actually accruing to the electric utility. If energy produced from a qualifying facility undergoes line losses such that the delivered power is not equivalent to the source of power it replaces, then the qualifying facility should be reimbursed only for the equivalent amount. If the load served by the qualifying facility is closer to the qualifying facility than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.

Subparagraph (4) provides that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases might result in net

[10] Such availability may, however, permit the utility to advance the retirement of its least effective units.

increased operating costs to the electric utility. Identification of these periods will be made by the State regulatory authority which has jurisdiction over the utility or by the nonregulated electric utilities. Comments received in response to the Staff discussion paper noted that if, for example, during low load periods, a utility were operating a nuclear plant as its most expensive unit, and were forced to cut back output from such a unit in order to accommodate a purchase from a qualifying facility, the utility would experience increased costs in increasing the output from the nuclear facility when the system demand increases.[11]

Thus, because the avoided cost is zero or actually involves expense to the utility, requiring the utility to purchase energy from a qualifying facility during such a period would not be just and reasonable to the consumers of the electric utility, because it would result in increased costs to the system's rate payers. Under the proposed § 292.104(a) an electric utility would not be required to make energy purchases during such a period.

Tax Issues

The Statement of the Committee of Conference states that

> • • • the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or the small power producer's power should not be burdened by the same examination as are utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.

We note that section 301(b)(2) of the Energy Tax Act of 1978[12] made eligible for increased business investment tax credit certain property that may be used by small power producers or cogenerators. However, section 301(b)(2)(B) excludes from such eligibility property "which is public utility property (within the meaning of section 46(f)(5) of the Internal Revenue Code of 1954)."[13] As a result, if a qualifying facility were to be classified as a public utility under section 46(f)(5) of the Internal Revenue Code, it would not be eligible for the increased investment tax credit otherwise available.

The Commission notes that a recent change[14] in Treasury Department regulations amended the definition of the exclusion "public utility property" for purposes of eligibility for the investment tax credit so as to exclude [from the definition] property used in the business of the furnishing or sale of electric energy if the rates are not subject to regulation that fixes a rate of return on investment. Prior to the change, any rate regulation made property subject thereto (and involved in the furnishing or sale of energy) public utility property.

The Commission observes that the rates for purchases set forth in this rulemaking for purchases of energy from qualifying facilities are *not* based on a rate of return on investment. As a result, the Commission believes that property owned by qualifying facilities should not be classified as public utility property under section 46(f)(5) of the Internal Revenue Code of 1954. If such property is not classified as public utility property, the qualifying facility will be eligible to receive the additional investment tax credit set out in section 301(b) of the Energy Tax Act of 1978. The Commission wishes to express its opinion on this matter in an effort to further encourage cogeneration and small power production by means of this rulemaking process.

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[11] Comments of Commonwealth Edison Company, filed August 1, 1979 at 4.

[12] Pub. L. No. 95-618, 26 U.S.C. §§ 46, 48, November 9, 1978.

[13] 21 U.S.C. § 48(e)(3)(b).

[14] Treasury Reg. § 1.48-3(g)(2), T.D. 7602 (March 23, 1979).

§ 292.106 Rates for sales.

Section 210(c) of PURPA provides that the rules requiring utilities to sell electric energy to qualifying facilities shall ensure that the rates for such sales are just and reasonable, in the public interest, and nondiscriminatory against qualifying cogenerators or small power producers. As noted in the Staff discussion paper,[15] this section contemplates rates formulated on the basis of traditional ratemaking (*i.e.*, cost of service) concepts.

Paragraph (a) provides that rates for sales from electric utilities to qualifying facilities shall not be discriminatory against such facilities in comparison to rates to other customers served by the electric utility. Paragraph (a) also states that such rates shall be just and reasonable and in the public interest.

A qualifying facility is entitled to purchase back-up or standby power at a rate which reflects the probability that the qualifying facility will or will not contribute to the need for utility capacity and the use of utility capacity.[16] Thus, when the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility if the utility would assess these costs to non-generating customers.[17]

Paragraph (b) provides that electric utilities must provide to qualifying facilities any services which would be provided by the electric utility to a retail customer who does not have his own generation.

Normally the determination of an appropriate rate to a class of customers is based on an examination of load data relating to such customers. At this time, however, even those utilities which have good load data regarding existing customer classes do not have load data regarding usage by qualifying cogeneration and small power production facilities. Until such data is collected, the Commission believes that rates for sales to qualifying facilities should be at least as favorable as those available to utility customers having comparable load characteristics or falling under similar load classifications.

Paragraph (c) sets forth certain types of service which electric utilities are required to provide to qualifying facilities even if such types of service are not provided to other customers. These types of service are: supplementary power, back-up power, interruptible power, and maintenance power. The Commission believes that this requirement is necessary to encourage small power production and cogeneration.

Supplementary power is power used by a facility in addition to that which it ordinarily generates on its own. Thus, a cogeneration facility with a capacity of ten megawatts might require five more megawatts from a utility on a continuing basis to meet its electric load of fifteen megawatts. The five megawatts supplied by the electric utility would normally be provided as supplementary power.

Back-up power is power available to replace power generated by a facility's own generation equipment. In the example provided above, a cogeneration facility might contract with an electric utility for the utility to have available ten megawatts, should the cogenerator's units experience an outage.

Interruptible power is power supplied by a utility on an "as available" basis. Because interruptible power normally is sold at a lower rate, a qualifying facility may wish to cease operations when utility power is interrupted rather than pay the higher rate necessary to assure firm supplementary supplies.

Maintenance power is supplied during scheduled outages. By prearrangement, a utility can agree to provide such power during periods when the utility's other loads are low, thereby avoiding

[15] Staff discussion paper, *supra*, at 14–20.
[16] Comments of ELCON (Electricity Consumer Resource Council), filed August 1, 1979, at 5.
[17] Comments of Consumers Power Company, filed August 1, 1979, at 3.

the imposition of large demands on the utility during peak periods.

Paragraphs (d)(1) and (d)(2) provide that rates for sales of back-up or maintenance power shall not be based on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur simultaneously or on the assumption that they will occur during the system peak. Like other customers, qualifying facilities have intraclass diversity. In addition, because of the variations in size and load requirements among various types of qualifying facilities, such facilities will have interclass diversity.

The effect of such diversity is that an electric utiliity supplying back-up or maintenance power to qualifying facilities will not have to plan for reserve capacity to serve such facilities on the assumption that every facility will use power at the same moment. The Commission believes that probabilistic analysis of their demand will show that a utility need not reserve capacity on a one-to-one basis to meet back-up requirements. Paragraphs (d)(1) and (d)(2) prohibit utilities from basing rates on the unsupported assumption that qualifying facilities will impose demands simultaneously and at system peak.

Paragraph (d)(3) provides that rates for sales from an electric utility to a qualifying facility shall take into account the extent to which a qualifying facility has coordinated periods of scheduled maintenance with an electric utility. If a qualifying facility coordinates periods of outage with an electric utility the demand that the qualifying facility imposes on the utility's system will not create capacity requirements to the same extent that such a demand would create if the utility were required to provide such service without prior notice.

§ 292.107 Simultaneous purchase and sale.

Section 292.107 deals with the situation referred to in the Staff discussion paper in which a cogenerator or small power producer desires to sell all of its output to a utility and purchase all of its needs from the utility simultaneously. As observed in the Staff discussion paper, and efficient use of society's resources requires that when there is a need for additional capacity, and a utility's customer can construct a new plant more cheaply than the utility can, he should be encouraged to do so.[18] A qualifying facility may have previously used a portion of its electric output to supply its own power needs. That it chose to generate its own electric power, rather than purchase such power from an electric utility, indicates that there were sufficient economic incentives to so act. To permit such a facility to sell that portion of its electric output to the utility at the utility's avoided costs and replace that electricity from the electric utility at non-incremental (and presumably lower) rates would increase the purchased power costs of the pruchasing utility and thus would increase the rates charged to the utility's other customers. The Commission believes that it is not necessary to the encouragement of cogeneration and small power production that a qualifying facility be permitted to obtain avoided cost-based rates for this portion of its electric output. Accordingly, the Commission proposes that for energy generated by a new facility or by capacity installed after the date of issuance of these rules, a qualifying facility be permitted to sell its output at rates established under the section 210(b) of PURPA pricing mechanism while simultaneously purchasing electric energy from a utility pursuant to its retail rate schedules.

[18] Staff discussion paper, *supra* at 24–25.

§ *292.108 Costs of interconnection.*

Paragraph (a) defines "interconnection costs" as the reasonable costs of connection, switching, metering, transmission, safety provisions and other costs to an electric utility resulting from interconnected operation between an electric utility and a qualifying facility.

Paragraph (b) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs. These costs are limited to the net increased costs imposed on an electric utility compared to those it would have incurred had it generated the energy itself or purchased an equivalent amount of energy or capacity from another source.

If, with the consent of a qualifying facility, an electric utility elects to transmit energy from the qualifying facility to another electric utility, the costs of transmission constitute interconnection costs as defined in this paragraph. Under paragraph (b), these costs must be borne by the qualifying facility unless the transmitting utility agrees to share them.

The cost responsibility of the qualifying facility was well summarized in comments by The Southern Company:

> We believe that the interconnection costs which should be addressed in the rules are those incremental costs that go beyond the cost to the system for connecting a normal (i.e. no generation) customer. These costs will include the additional relaying, switching, metering, line, and protective equipment—inclusive of equipment changeout cost—required in the general vicinity of the facility because of the customer's generation. Recognition must be given to the fact that protection goes beyond the protection of equipment and personnel of the qualifying facility and utility. The rules also must provide for the protection of other customers of the utility that may be affected by the operation of the qualifying facility.[19]

Thus, it is only the additional costs which result from interconnected operation for which the qualifying facility is responsible; if the utility would have provided retail service to the customer, those expenses may not be assessed against the qualifying facility merely because the facility is also supplying power and energy. If, however, as a result of the qualifying facility's export of power, the utility is required to install additional switching, safety or other equipment, the qualifying facility is responsible for those expenses.

Paragraph (c) provides that a qualifying facility must reimburse an electric utility which sells capacity or energy to the qualifying facility for interconnection costs resulting from such sale. Ordinarily, the service obligation of an electric utility will contain standard procedures for the allocation of interconnection costs between a retail customer and the electric utility. Paragraph (c) also provides that interconnection costs to qualifying facilities shall not be discriminatory in relation to the practices of the electric utility with regard to other retail customers.

§ *292.109 System emergencies.*

Paragraph (a) provides that, except as provided under section 202(c) of the Federal Power Act or pursuant to a contract or agreement between a qualifying facility and an electric utility, no qualifying facility shall be compelled to provide energy or capacity to the electric utility during an emergency beyond the extent provided by agreement between the qualifying facility and the utility.

Many comments from cogenerators and small power producers expressed concern that, during a system emergency, they might be required to make available all of their generation to the utility. Such a requirement might interrupt industrial processes with resulting damage to equipment and manufactured goods. Many industries install their own generating equipment in order to insure that even during a system emergency, their supply of power is not interrupted. To put in

[19] Comments of The Southern Company, filed July 30, 1979, at 5.

jeopardy the availability of power because of the facility's ability to provide power to the system during non-emergency periods would result in the discouragement of interconnected operation and a resultant discouragement of cogeneration and small power production. The Commission therefore proposes that the qualifying utility's obligation to provide power be established through contract.

In order to receive full credit for capacity, a qualifying facility must offer power during system emergencies to the same extent that it has agreed to provide power at the purchasing utility's discretion. For example, a 30 megawatt cogenerator may require 20 megawatts for its own industrial purposes, and thus may contract to provide 10 megawatts of capacity to the purchasing utility. During an emergency, the cogenerator must provide the 10 megawatts contracted for to the utility; it need not disrupt its industrial processes by supplying its full capability of 30 megawatts. Of course, if it should so desire, a cogenerator could contractually agree to supply the full 30 megawatts during system emergencies. The availability of such additional back-up capacity should increase utility system reliability, and should be accounted for in the utility's rates for purchases from the cogenerator.

Paragraph (b) provides that an electric utility may discontinue purchases from a qualifying facility during a system emergency if such a purchase would contribute to the emergency. In addition, during system emergencies, a qualifying facility must be treated on a non-discriminatory basis—i.e., on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption in service.

§ 292.110 Standards for operating reliability.

Section 210(a) of PURPA states that the rules requiring electric utilities to buy from and sell to qualifying facilities shall include provisions respecting minimum reliability of qualifying facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Staff's analysis presented in the discussion paper regarding reliability of a particular qualifying facility concluded that every incidence of qualifying facility reliability can be accounted for through price; namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases of its power by the utility. The majority of comments received regarding this issue endorsed the Staff's recommendation. Accordingly, the Commission proposes that there be no specific standard relating to the reliability in the sense of ability to provide power for qualifying facilities.

Many commentors have proposed that the Commission's rules ensure that interconnection with qualifying facilities does not disrupt system reliability. One commentor proposed that qualifying facilities must automatically disconnect from utility lines upon interruption or interference with utility service, or upon the flow of excessive current between the utility system and the non-utility generator.[20]

It is the Commission's understanding that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages. This section accordingly provides that any qualifying facility may be subject to reasonable standards to ensure system safety and reliability in interconnected operations. Each State regulatory authority and nonregulated electric utility is permitted to establish standards for interconnected operation between electric utilities and qualifying facilities. These standards may be recommended by a utility or any other person. The standards must be accompanied by a statement showing the need for the standard on the basis of

[20] Comments of Illinois Power Company, filed August 14, 1979.

system safety and operating requirements.

Subpart C

Summary of This Subpart

Rules proposed in this subpart are intended to carry out the responsibility of the Commission to encourage cogeneration and small power production by clarifying to all parties concerned the nature of the obligation to implement the Commission's rules under section 210.

In the Commission's view, section 210(f) affords the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the Commission's rules so long as the manner chosen is reasonably designed to implement the requirements of Subpart A. The Commission recognizes that many States and individual nonregulated electric utilities have ongoing programs to encourage small power production and cogeneration. The Commission also recognizes that economic and regulatory circumstances vary from State to State and utility to utility. It is within this broad latitude, and with the recognition of the work already begun and of the variety of local conditions that the Commission proposes to promulgate its regulations requiring implementation of rules issued under section 210.

Because of the Commission's desire not to create unnecessary burdens at the State level, these proposed rules provide a procedure whereby a State regulatory authority or nonregulated electric utility may apply for a waiver if it can demonstrate that compliance with certain requirements of Subpart A is not necessary to encourage congeneration or small power production and is not otherwise required under section 210.

Implementation

Section 210(f) of PURPA requires that within one year after the date that this Commission prescribes its rules under subsection (a), and within one year of the date any of these rules is revised, each State regulatory authority and each nonregulated electric utility, after notice and opportunity for hearing, must implement the rules or revisions thereof, as the case may be.

The obligation to implement section 210 rules is a continuing obligation which begins within one year after promulgation of such rules. The requirements to implement may be fulfilled either through (1) the enactment of laws or regulations at the State level, (2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission, or (3) by any other action reasonably designed to implement the Commission's rules. In the first case, implementation would consist of the issuance of rules after notice, and an opportunity for c hearing. In the second case, the State regulatory authority or nonregulated utility would be required to hold hearings regarding its proposed procedure for operating on a case-by-case basis, within the one-year statutory period.

Review and Enforcement

Section 210(g) of PURPA provides one of the means of obtaining judicial review of a proceeding conducted by a State regulatory authority or nonregulated utility for purposes of implementing the Commission's rules under section 210. Under subsection (g), review may be obtained pursuant to procedures set forth in section 123 of PURPA. This section contains provisions with regard to judicial review and enforcement of determinations made by State regulatory authorities and norregulated utilities under Subtitle A, B, or C of Title i in the appropriate State court. These provisions also apply to review of any action taken to implement the rules under section 210. This means that persons can bring actions in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations. Section 123(c)(2) of PURPA restates the

requirements of section 123(c)(1) as they apply to Federal agencies. This distinction between Federal agencies and non-Federal agencies also applies to review and enforcement of the implementation of the rules under section 210.

Finally, the Commission believes that review and enforcement of implementation under section 210 of PURPA, can consist not only of review and enforcement as to whether the State regulatory authority or nonregulated electric utility has conducted the initial implementation properly—namely put into effect regulations implementing section 210 rules or procedures for that implementation, after notice and an opportunity for a hearing. It can also consist of review and enforcement with regard to the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, of its regulations or any other provision it may have adopted to implement the Commission's rules under section 210.

Section 210(h)(2)(A) of PURPA states that the Commission may enforce regulations under section 210(f). The Congress has provided not only for private causes of action in State courts to obtain judicial review and enforcement of the implementation of the Commission's rules under section 210, but has also given to the Commission that authority.

Section-by-Section Analysis

§ 292.301 Implementation by State regulatory authorities and nonregulated utilities.

Paragraph (a) of § 292.301 sets forth the obligation of each State regulatory authority to commence implementation of Subpart A within one year of the date these rules take effect. In complying with this paragraph the State regulatory authorities are required to provide for notice and opportunity for public hearing. As described in the summary of this part, such implementation may consist of the adoption of the Commission's rules, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart A, or any other action reasonably designed to implement Subpart A.

This section does not cover one provision of Subpart A which is not required to implemented by the State regulatory authority or nonregulated electric utility. This provision is § 292.103, the implementation of which is subject to § 292.302, which will be discussed below.

Subsection (b) sets forth the obligation of each nonregulated electric utility to commence, after notice and opportunity for public hearing, implementation of Subpart A. The nonregulated electric utilities, being both the regulator and the utility subject to the regulation, may satisfy the obligation to commence implementation of Subpart A through issuance of regulations, an undertaking to comply with Subpart A, or any other action reasonably designed to implement that subpart. Paragraph (c) sets forth a reporting requirement under which each State regulatory authority and nonregulated electric utility is to file with the Commission not later than one year after these rules take effect, a report describing the manner in which it is proceeding to implement Subpart A.

§ 292.302 Implementation of reporting objectives.

The obligation to comply with § 292.103 is imposed directly on electric utilities. This is different from the rest of Subpart A where the obligation to act is imposed on the State regulatory authority or nonregulated electric utility in its role as regulator. The Commission is exercising its authority under section 133 of PURPA to require this reporting.

Any electric utility which fails to comply with the requirements of § 292.103(b) is subject to the same penalties as it might receive as a result of a failure to comply with the requirements of the Commission's

regulations issued under section 133 of PURPA. As stated earlier in this preamble, the data required by § 292.103 will form the basis for the rates for purchases; § 292.103 is thus a critical element in the program this Commission is providing. The Commission believes that, with regard to utilities subject to section 133 of PURPA, the Commission may exercise its authority under section 133 to require the data required by § 292.102(b) on the basis that the Commission finds such information necessary to allow determination of the costs associated with providing electric services. With regard to utilities not subject to section 133, if they fail to provide the data called for in § 292.103(c), the Commission may compel its production under the Federal Power Act and other statutes which give the Commission authority to require reporting of this data.

§ 292.303 Waivers.

Paragraph (a) provides for a procedure by which any State regulatory authority or nonregulated electric utility may apply for a waiver from the application of any of the requirements of Subpart A other than § 292.103. This provision is included in recognition of the need for the Commission to afford flexibility to the States and nonregulated utilities to implement the Commission's rules under section 210.

Paragraph (b) provides that any electric utility subject to the requirements of § 292.103(c) may apply to the Commission for a waiver from the application of such requirements. This provision is included to afford to the Commission flexibility to enforce the obligations of § 292.103(c) so that it may consider the burden which may be placed on the utility by application of this section.

Subpart D—Exemption of Qualifying Small Power Production and Cogeneration Facilities From Certain Federal and State Laws and Regulations

§ 292.401 Exemptions for qualifying facilities from the Federal Power Act.

Section 210(e) of PURPA states that the Commission shall prescribe rules under which qualifying facilities are exempt in part from the Federal Power Act, from the Public Utility Holding Company Act of 1935, from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. As noted in the Staff discussion paper, the Congress intended the Commission to make liberal use of its exemption authority in order to remove the disincentive of utility-type regulation. The Commission believes that broad exemption is appropriate.

Section 210(e)(2) of PURPA provides that the Commission is not authorized to exempt small power production facilities of 30 to 80 megawatt capacity from any of these laws. An exception is made for small power production facilities using biomass. Such facilities between 30 and 80 megawatts may be exempted from the Public Utility Holding Company Act of 1935 and from State regulations but may not be exempted from the Federal Power Act.

Paragraph (a) sets forth those facilities eligible for exemption. Paragraph (b) provides that facilities described in paragraph (a) shall be exempted from all but certain specified sections of the Federal Power Act.

Section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from any license or permit requirement under Part I of the Federal Power Act. Accordingly, the Commission proposes not to exempt qualifying facilities from Part I of the Federal Power Act. The Commission

recently issued simplified procedures for obtaining water power licenses for hydroelectric projects of 1.5 megawatts or less, and has issued proposed regulations to expedite licensing of existing facilities.[21]

As noted in the discussion paper, cogenerators and small power production facilities could be the subject of an order under section 202(c) of the Federal Power Act requiring them to provide energy if the Economic Regulatory Administration determines that an emergency situation exists. Because application of this section is limited to emergency situations and is not affected by the fact that a facility attains qualifying status or engages in interchanges with an electric utility, the Commission proposes that qualifying facilities not be exempted from section 202(c) of the Act.

Sections 203, 204, 205, 206, 208, 301, 302 and 304 of the Act reflect traditional rate regulation or regulation of securities of public utilities. The Commission proposes that qualifying facilities be exempted from these sections of the Federal Power Act.

Section 305(c) of the Act imposes certain reporting requirements on interlocking directorates. The Commission proposes that any person who otherwise is requred to file a report regarding interlocking positions not be exempted from such requirement because he or she is also a director or officer of a qualifying facility.

Finally, the enforcement provisions of Part III will continue to apply with respect to the sections of the Federal Power Act from which qualifying facilities are not exempt.

§ 292.402 Exemptions for qualifying facilities from the Public Utility Holding Company Act and Certain State Laws and Regulations.

Under section 210(e) of PURPA the Commission can exempt qualifying facilities from regulation under the Public Utility Holding Company Act of 1935 and State laws and regulations concerning rates or financial organizations. Only cogeneration facilities and small power production facilities of 30 megawatts or less may be exempted from both of these laws, with the exception that any qualifying small power production facility (i.e., up to 80 megawatts) using biomass as a primary energy source can be exempted from these laws.

The Staff discussion paper recommended that, where a qualifying facility is subjected to more stringent regulation than other companies solely by reason of the fact that it is engaged in the production of electric energy, these more stringent requirements should be eased through exemption of qualifying facilities. By excluding any qualifying facility from the definition of an "electric utility company" under section 79 (b)(3) of the Public Utility Holding Company Act of 1935, such facilities would be removed from Public Utility Holding Company Act regulation which is applied exclusively to electric utility companies. Moreover, by excluding qualifying facilities from this definition, parent companies of qualifying facilities would not be subject to additional regulation as a result of electric activities of their subsidiaries. The Commission therefore believes that in order to encourage cogeneration and small power production it is necessary to exempt cogenerators and small power producers from the provisions of the Public Utility Holding Company Act of 1935.

Accordingly, paragraph (b) states that no qualifying facility shall be considered to be an "electric utility company", as defined in section 79 (b)(3) of the Public Utility Holding Company Act of 1935.

Section 210(e) of PURPA states that qualifying facilities which may be exempted from the Public Utility Holding Company Act may also be

[21] *See* Order No. 11, Simplified Procedures for Certain Water Power Licenses, Docket No. RM79-9, issued September 5, 1978, and Application for License for Major Project—Existing Dam, Docket No. RM79-36, 44 F.R. 24095 (April 21, 1979).

exempted from State laws and regulations respecting the rates or respecting the financial or organization regulation of electric utilities. The Staff discussion paper sets forth two approaches to be taken to exemption from State law. One would be to analyze the laws of each State and apply the exemptions citing specific sections of State law and regulations. The second approach discussed would be to make a broad proscription from State laws and regulations which would conflict with the State's implementation of the Commission's rules under section 210.

All of the comments received recommended the broader approach. The Commission believes that such broad exemption is necessary to encourage cogeneration or small power production. Accordingly, subparagraph (c)(1) provides that any qualifying facility shall be exempt from State laws and regulations respecting rates for sales of electric energy to electric utilities, and from financial and organizational regulation of electric utilities.

Subparagraph (c)(2) provides that, upon request of a State regulatory authority a nonregulated electric utility, the Commission may limit the applicability of the broad exemption from the State laws. This provision is intended to add flexibility to the exemption.

The Commission perceives that there may be instances in which a qualifying facility would wish to have an interpretation of whether or not it is subject to a particular State law in order to remove any uncertainty. Under subparagraph (c)(2), the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

Written Comments and Public Hearings

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should reference Docket No. RM 79-55 on the outside of the envelope and on all documents submitted to the Commission. In order that the Commission be able to take into account as many comments as possible, the Commission requests that persons submitting comments assist in three ways. First, persons should identify specfically the section or subpart they are addressing. Second, comments should clearly state whether they involve technical, policy or legal matters. Finally, where comments urge a different approach from one presented, specific alternative language should be proposed to the extent practicable.

In addition, the preliminary Environmental Assessment prepared by Commission Staff regarding the Commission's proposed rules implementing sections 201 and 210 of PURPA is available in the Commission's Office of Public Information. As stated in the Request for Further Comment on Proposed Rulemaking Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration issued today, the Commission is seeking comments on specific issues relating to the preliminary Environmental Assessment.

The Commission has also received many comments in response to the Staff discussion paper and the notice of proposed rulemaking in Docket No. RM79-54. All comments filed in response to those documents are being made part of the record and will be considered in the determination of the final rule in this proceeding.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission by December 1, 1979, will be considered prior to the promulgation of final regulations.

In addition, the Commission will conduct public hearings in several cities at which interested persons will have the opportunity to present their views.

Places, dates and times will be announced shortly.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, it is proposed to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

(1) Subchapter K is amended in the table of contents by deleting the title for Part 292 and substituting the following in lieu thereof:

PART 292—REGULATION OF SMALL POWER PRODUCTION AND COGENERATION FACILITIES UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978.

(2) Subchapter K is further amended in the table of contents to Part 292 and in the text of the regulations by changing the title to Part 292 and by adding new Subparts A, C, and D to read as follows:

PART 292—REGULATION OF SMALL POWER PRODUCTION AND COGENERATION FACILITIES UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

Subpart A—Rates for Sales Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities

Sec.

292.101 Scope.
292.102 Definitions.
292.103 Availability of Electric Utility System Cost Data.
292.104 Electric Utility Obligations Under This Subpart.
292.105 Rates for Purchases.
292.106 Rates for Sales.
292.107 Simultaneous Purchase and Sale.
292.108 Costs of Interconnection.
292.109 System Emergencies.
292.110 Standards for Operating Reliability.

* * * * *

Subpart C—Implementation

292.301 Implementation by State Regulatory Authorities and Nonregulated Electric Utilities.
292.302 Implementation of Reporting Objectives.
292.303 Waiver.

Subpart D—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities From Certain Federal and State Laws and Regulations

292.401 Exemptions for Qualifying Facilities from the Federal Power Act.
292.402 Exemptions for Qualifying Facilities from the Public Utility Holding Company Act and Certain State Laws and Regulations.

Authority: This part issued under the Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.

Subpart A—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ 292.101 Scope.

(a). *Applicability.* This subpart applies to the regulation of sales and purchases of electric energy and capacity between qualifying cogeneration and small power production facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart—

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for purchases or sales, or terms or conditions relating to such sales, which differ from the rate or terms which would otherwise be required by this subpart, or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility.

§ 292.102 Definitions.

(a) *General rule.* Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they

have under PURPA, unless further defined in this part.

(b) *Definitions:* For purposes of this part:

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under § 292.208 of the Commission's regulations;

(2) "Purchase" means the purchase of electric energy or capacity from a qualifying facility by an electric utility;

(3) "Sale" means the sale of electric energy or capacity by an electric utility to a qualifying facility;

(4) "System emergency" means a condition on a utility's system which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property;

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the costs to the electric utility of electric energy or capacity or both which, but for the purchase from such cogenerator or small power producer, such utility would generate itself or purchase from another source.

§ 292.103 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in subparagraph (2), paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until June 30, 1982.

(b) *General Rule.* Not later than June 30, 1980, and every two years thereafter, each regulated electric utility to which this section applies shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility to which this section applies shall maintain for public inspection, the following data:

(1) The estimated avoided cost of energy on the electric utility's system for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of one hundred megawatts or less for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than ten percent of the system peak demand, for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the immediately preceding year, and on an estimated cents per kilowatt-hour basis for the current calendar year and each of the next 5 years;

(2) The electric utility's plan and schedule for the addition of capacity, for purchases of firm energy and capacity, and for capacity retirements for each of the next 10 years; and

(3) The estimated costs at completion, on the basis of dollars per kilowatt, of the planned capacity additions and planned firm purchases. These costs should be expressed in terms of individual generating units and by planned firm purchases.

(c) *Special Rule.* Each electric utility (other than any electric utility to which paragraph (b) applies) shall, upon request of a qualifying facility, provide sufficient data to enable such qualifying facility to determine the electric utility's avoided costs for any period described in paragraph (b). If any such electric utility fails to provide such information or request, the qualifying facility may apply to the Commission for an order requiring that the information be provided.

§ 292.104 Electric utility obligations under this subpart.

(a) *Obligation to Purchase from Qualifying Facilities.* Except during periods identified in § 292.105(e), each electric utility shall purchase in accordance with § 292.105 any capacity or energy which is made available either directly from the qualifying facility or which is transmitted to such utility from the qualifying facility through the facilities of another electric utility.

(b) *Obligation to Sell to Qualifying Facilities.* Each electric utility shall sell to any qualifying facility energy and capacity requested by such qualifying facility in accordance with § 292.106.

(c) *Obligation to Interconnect.* Any electric utility shall make all interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligations for the cost of any such interconnection shall be determined in accordance with § 292.108.

(d) *Transmission of Purchases to Other Electric Utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase capacity or energy from such qualifying facility may transmit the energy to any other electric utility. Any electric utility to which such energy is transmitted shall purchase such energy under this subpart as if such qualifying facility were supplying energy and capacity directly to such electric utility. The cost of transmission shall be assigned to the qualifying facility pursuant to § 292.108 of these rules. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted to reflect line losses pursuant to § 292.105(d)(3).

(e) *Parallel Operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any relevant standards established pursuant to § 292.110.

§ 292.105 Rates for purchases.

(a) *Rates for Purchases.* Rates for purchases of energy and capacity from any qualifying facility:

(1) Shall be just and reasonable to the electric consumer of the electric utility and in the public interest;

(2) Shall not discriminate against qualifying cogeneration and small power production facilities; and

(3) Shall not exceed the avoided costs of such a purchase. There is a rebuttable presumption that the rate for purchases meets the requirements of this paragraph if the rate reflects the avoided costs resulting from such purchase as determined on the basis of the cost of energy and capacity set forth pursuant to § 292.103(b) or (c).

(b) *Tariffs for Purchases From Facilities of Ten Kilowatts or Less.* Each electric utility, upon request of a qualifying facility, shall establish a tariff or other method for setting forth standard rates for purchases from qualifying facilities with a design capacity of 10 kilowatts or less.

(c) *Purchases "As Available" or Pursuant to a Legally Enforceable Obligation.* A qualifying facility shall have the option either to provide energy or capacity to an electric utility—

(1) As the qualifying facility determines such energy or capacity to be available for such purchases, in which case the rates for such purchases may be based on the purchasing utility's avoided energy costs, or

(2) Pursuant to a legally enforceable obligation for the delivery of energy or capacity at a future date, in which case the rates for purchases may be based on estimates of future avoided costs of energy or capacity.

(d) *Factors Affecting Rates For Purchases.* In implementing the provisions of this subpart, a State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility shall consider with regard to rates for purchases the following factors:

(1) The availability of capacity from a qualifying facility during system daily and seasonal peak periods, including—

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The qualifying facility's ability and willingness to provide energy or capacity during system emergencies;

(iii) The length, frequency, and scheduling flexibility of scheduled maintenance by the qualifying facility;

(iv) The expected or demonstrated reliability of the qualifying facility; and

(v) The length of any contract term between the electric utility and the qualifying facility and its termination notice requirements or the length of any legally enforceable obligation to provide energy or capacity undertaken by the qualifying facility;

(2) The relationship of energy or capacity from a qualifying facility to an electric utility's capacity and energy needs as expressed in § 292.103, including:

(i) The ability of the electric utility to reduce or avoid costs, including the deferral of capacity additions, as a result of the availability individually or in the aggregate from qualifying facilities; and

(ii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated or purchased an equivalent amount of electric energy.

(e) *Periods During Which Purchases Not Required.* An electric utility will not be required to purchase electric energy and capacity during any period identified by the State regulatory authority having jurisdiction over the rates of such utility, or the nonregulated electric utility, during which purchases from qualifying facilities might result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated or purchased an equivalent amount of electric energy.

§ 292.106 Rates for sales.

(a) *General Rules.* (1) Rates for sales shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for sales shall be just and reasonable and in the public interest.

(b) Each electric utility shall provide electric energy and capacity and other services to any qualifying facility, at a rate at least as favorable as would be provided to a customer who does not have his own generation. The costs of interconnection shall be assigned pursuant to § 292.108 of this part.

(c) *Additional Services to be Provided by Qualifying Facilities.* Each electric utility shall provide to any qualifying facility the following types of service, even if such types of service are not provided to other retail customers:

(1) Supplementary power;

(2) Back-up power;

(3) Interruptible power; and

(4) Maintenance power.

(d) *Rates for Sales of Back-Up and Maintenance Power.* The rate for sales of back-up power or maintenance power—

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously;

(2) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities will occur during the system peak; and

(3) Shall take into account the extent to which a qualifying facility has coordinated periods of scheduled maintenance with such electric utility.

§ 292.107 Simultaneous purchase and sale.

A qualifying facility shall be permitted to receive rates established pursuant to § 292.105(a) for the electric energy and capacity generated by the facility, while simultaneously buying energy and capacity from such utility for use in the facility at rates established in accordance with § 292.106(a), to the

extent that such purchases are produced by capacity the construction of which was commenced after the date of issuance of this part.

§ 292.108 Costs of interconnection.

(a) *Definition.* For purposes of this subpart, "interconnection costs" means the costs of connection, switching, metering, transmission, safety provisions and other costs incurred by the utility reasonably resulting from interconnected operation between an electric utility and a qualifying facility.

(b) *Reimbursement for Interconnection Costs for Purchases.* Each qualifying facility must reimburse any electric utility which purchases capacity or energy from such qualifying facility for any interconnection costs. These costs are limited to the difference between the interconnection costs and those costs which the purchasing utility would incur if it did not make such purchases but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy from other sources.

(c) *Reimbursement for Interconnection Costs for Sales.* Each qualifying facility must reimburse any electric utility which sells capacity or energy to such qualifying facility for any interconnection costs. The apportionment of interconnection costs between such qualifying facility and electric utility under this paragraph shall not discriminate against any qualifying facility in comparison to any other customers served by the electric utility.

§ 292.109 System emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent provided by agreement between such qualifying facility and electric utility or to the extent ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of Purchases and Sales During System Emergencies.* During any system emergency, an electric utility may discontinue—

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.110 Standards for operating reliability.

Any qualifying facility may be subject to reasonable standards to ensure system safety and reliability in interconnected operations. Such standards may be recommended by any electric utility, or by any other person. Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or any nonregulated electric utility may establish such standards as it determines necessary to carry out the purposes of this section. Such standards must be accompanied by a statement setting forth the need for such standards on the basis of system safety and reliability requirements.

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Subpart C—Implementation

§ 292.301 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) *State Regulatory Authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart A (other than § 292.103 thereof). Such implementation may consist of the issuance of regulations; an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart A, or any other action reasonably designed to implement such subpart (other than § 292.103 thereof).

(b) *Nonregulated Electric Utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing, commence implementation of Subpart A (other than § 292.103 thereof). Such implementation may consist of the

issuance of regulations, an undertaking to comply with Subpart A, or any other action reasonably designed to implement such subpart (other than § 292.103 thereof).

(c) *Reporting Requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonregulated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart A (other than § 292.103 thereof).

§ 292.302 Implementation of reporting objectives.

Any electric utility which fails to comply with the requirements of § 292.103(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.303 Waivers.

(a) *State regulatory authority and non-regulated utility waivers.* Any State regulatory authority or non-regulated electric utility may apply for a waiver from the application of any of the requirements of Subpart A (other than § 292.103 thereof).

(b) *Electric utility waiver.* Any electric utility may apply for a waiver from the application of any of the requirements of § 292.103(c).

(c) *Commission action.* The Commission will grant such a waiver only if an applicant under paragraph (a) or (b) demonstrates that compliance with the requirements of Subpart A or § 292.103, as the case may be, is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

Subpart D—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities From Certain Federal and State Laws and Regulations

§ 292.401 Exemptions for qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to:

(1) Qualifying cogeneration facilities, and

(2) Qualifying small power production facilities which have a power production capacity which does not exceed 30 megawatts.

(b) *General Rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except—

(1) Sections 1–30;

(2) Section 202(c);

(3) Section 305(c); and

(4) Any necessary enforcement provisions of Part III with regard to the sections listed in (1), (2) and (3).

§ 292.402 Exemptions for qualifying facilities from the Public Utility Holding Company Act and certain State laws and regulations.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.401(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* Any qualifying facility described in paragraph (a) shall not be considered to be an "electric utility company" as defined in section 79(b)(3) of the Public Utility Holding Company Act of 1935.

(c) *Exemption from Certain State Laws and Regulations.*

(1) Any qualifying facility shall be exempted from State laws and regulations respecting:

(i) The rates for sales of electric energy by qualifying cogeneration and small power production facilities to electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider any limitation of the application of subparagraph (1).

(3) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

¶ 32,040 Small Power Production and Cogeneration—Qualifying Status; Request for Further Comments on Proposed Rulemaking

44 F. R. 61205 (October 24, 1979).

18 CFR Part 292

[Docket No. RM79-54]

Small Power Production and Cogeneration—Qualifying Status; Request for Further Comments on Proposed Rulemaking

October 19, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Request for Further Comments on Proposed Rulemaking.

SUMMARY: The proposed rules set forth the procedure under which small power production facilities and cogeneration facilities may be certified as qualifying facilities pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules are being renoticed so that the Commission may elicit comment on the preliminary Environmental Assessment of the combined environmental effects of these rules and its companion rulemaking, RM79-55, which implements section 210 of PURPA. The Commission also seeks comment on the interrelationship between these two rulemakings.

Public Hearings: Provision for oral comment on these issues will be made at the public hearings which will be held on the Notice of Proposed Rulemaking in RM79-55. Dates and locations will be announced.

DATE: Written comments by December 1, 1979.

ADDRESS: All responses to reference Docket No. RM79-54, and to be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Adam Wenner, Executive Assistant to the Associate General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8171.

SUPPLEMENTARY INFORMATION:

The Commission is renoticing the proposed rulemaking[1] which establishes rules under which small power production facilities and cogeneration facilities may be certified as qualifying facilities under section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Contemporaneously, the Commission is issuing the Notice of Proposed Rulemaking Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, in Docket No. RM79-55.

Section 210 Requires the Commission to prescribe rules which the Commission determines necessary to encourage small power production and cogeneration, including rules regarding rates and exemptions for qualifying small power production and cogeneration facilities.

Background

The purpose of renoticing Docket No. RM79-54 at this time is twofold. First, the Commission wishes to provide interested persons the opportunity to comment on its findings with respect to the environmental impacts of the two proposed rules. Second, the Commission seeks comments on the interrelationship between the proposed rules issued pursuant to sections 201 and 210 of PURPA.

The implementation of section 201 as provided in Docket No. RM79-54 is one element in a two-part program to encourage small power production and cogeneration. That rulemaking sets forth

[1] Proposed Rulemaking Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities, Docket No. RM79-54, issued June 27, 1979 (44 F.R. 38873, July 3, 1979).

procedures under which certain facilities could become eligible to receive the incentives which were to be provided in the second part of the program. Docket No. RM79–55 implements this second element.

In the Staff discussion paper regarding issues arising under section 210, issued as part of Docket No. RM79–55 for comment on June 26, 1979, the Commission staff set forth the opinion that any environmental effects attributable to the encouragement of cogeneration or small power production under sections 201 and 210 of PURPA would arise from the combined effect of the two rules. The Commission staff has prepared a preliminary Environmental Assessment (EA) describing the environmental effects of the two proposed rules.

Summary of Preliminary Environmental Assessment

Briefly, the preliminary EA concludes that with regard to most of the technologies affected, the impact of the proposed rules will not significantly affect the quality of the human environment. The EA notes that at certain levels of usage and under specified conditions, the encouragement of certain technologies provided by these rules may produce isolated instances of adverse environmental effects. With regard to the use of all technologies encouraged by the Commission's rules, their increased use will result in less need for utility generation of electric energy and utility construction of new plants than would otherwise be necessary. These reductions should result in decreased emissions associated with the production of electric energy at central station utility plants, and the removal of environmental effects associated with new utility plant construction. In addition, the use of certain technologies will cause beneficial environmental effects, such as reduced temperatures of emissions.

The preliminary EA concludes that, except with regard to biomass, centralized solar energy systems (thermal and photovoltaic), and diesel cogeneration, the issuance of the rules implementing sections 201 and 210 of PURPA will not constitute a major Federal action significantly affecting the quality of the human environment. The effects of these regulations on biomass, centralized solar energy systems, and diesel cogeneration technologies may significantly affect the human environment and thus may require the preparation of an Environmental Impact Statement (EIS).

Cogeneration

The preliminary Environmental Assessment notes that, by using fuel more efficiently, cogeneration systems use less fuel and produce less emissions than would be produced if the electric energy and thermal energy were produced separately. The more efficient use of energy will cause some reduction in utility emissions, as a result of reductions in demand for utility-supplied energy and capacity. In addition, by reducing the temperature of gaseous and water wastes, cogeneration can decrease adverse effects associated with the discharge of heat. Therefore, the preliminary EA concludes that, with the exception noted below, the impact of the Commission's rules on cogeneration will not produce significant environmental effects.

Diesel Cogeneration

In the analysis of the use of diesel cogeneration in institutional, residential or commercial systems, the preliminary EA noted that in high-density urban areas, the use of a large number of clustered sources could create significant environmental impacts. The Assessment notes that the price of diesel fuel may inhibit the growth of this technology. It concludes that the Commission's rules *may* cause significant environmental effects with regard to this technology, but that further study is necessary.

Small Power Production—Solar Energy Systems

The preliminary EA concludes that, except for the case of centralized solar energy systems, the impact of the Commission's rules on solar energy systems in general will not cause significant adverse environmental effects. However, the preliminary EA states that the issuance of these rules may provide incentives for small power production facilities utilizing centralized systems of solar energy. The majority of centralized systems will, due to generating capacity (greater than 80 MW), fall outside the purview of these rulemakings.

The preliminary EA finds that the proposed rulemakings could result in the use of centralized solar energy systems (thermal and electrical) in the upper ranges of generating capacity addressed by these rules. The preliminary EA recognizes that the possible impacts on land use, climate, soil, and ecosystems *may* be significant. Additional quantitative data are required to assess the severity of these impacts. The preliminary EA recommends further study on the effect of these rules on this technology.

Biomass

The issuance of these rules provides incentives for small power production facilities utilizing biomass as a fuel source. The preliminary EA concludes that the possible adverse impacts to land use, soil, ecosystems and water resulting from the encouragement of biomass technology may be significant. The EA recommends additional study concerning the impact of these rules on the growth of biomass technology.

Wind Energy Conversion Systems

With regard to Wind Energy Conversion Systems (WECS), the preliminary EA determined that interference with electromagnetic radiation, hazards from blade throw, and danger of bird collision may occur. The level of these effects is not considered to comprise a significant adverse environmental effect.

Geothermal Technology

The preliminary EA finds that geothermal technology may affect air and water quality. These impacts should not, however, be significant.

Small Hydro

The preliminary EA notes that qualification of hydroelectric facilities is limited to facilities at existing dams, or those facilities not requiring an impoundment. It points out that instances of significant environmental impact from facilities added at existing dams are rare. It further observes that almost all such facilities are subject to Commission licensing and that the Commission's licensing procedures will assure case-by-case review of any adverse effects associated with the construction or operation of these hydroelectric projects. The preliminary EA concludes that any adverse environmental effects of these rules with respect to hyroelectric facilities will not be significant.

Waste

The preliminary EA discusses the environmental effects of municipal, agricultural and industrial waste. The use of waste emissions. However, the use of wastes will reduce landfill requirements and municipal incinerator and recycling loads. Based on these positive environmental effects, the preliminary EA finds that the impact of the Commission's rules on these technologies will not significantly affect the environment.

Reduction of Utility Production of Energy and Construction of Capacity

By obtaining electric energy from cogeneration and small power production, utilities can reduce the burning of fuel and the construction of plants than would otherwise be required. These reductions will cause decreases in the adverse environmental

effects associated with these activities. The preliminary EA thus concludes that in this respect the Commission's rules will have positive environmental effects

Commission Findings

On the basis of the current record, the Commission has determined that, with certain exceptions, the proposed rules under sections 201 and 210 of PURPA will not constitute a major Federal action significantly affecting the quality of the human environment. The Commission recognizes that the existing record (including the preliminary Environmental Assessment) shows that the impact of the proposed rules on the use of biomass, centralized solar energy systems, and diesel cogeneration *may* significantly affect the environment.

The foregoing is not intended to indicate a final judgment that the proposed PURPA rules as applied to those technologies *will* significantly affect the environment. Rather, the Commission adopts the view that the proposed rules, if promulgated without modification, potentially could have significant effects as described in the preliminary Environmental Assessment.

The Commission invites public comment on (a) the finding that, except as specifically noted above, the proposed rules will not be a major Federal action significantly affecting the quality of the human environment; (b) the finding that under the conditions noted above there *may* be significant effects from the proposed rules; and (c) the possibility that any potentially significant adverse effects could be sufficiently mitigated or eliminated by modifying the proposed qualifying rules to reflect one or more of the alternatives discussed below.

Alternatives

The Commission believes that certain substantive or procedural modifications to the proposed rules might mitigate any potential adverse effects associated with the three technologies identified above. These modifications include:

(1) Setting a high minimum size cutoff for potentially environmentally harmful technologies;

(2) Setting restrictions on qualifying status for facilities using certain high emission fuels or failing to meet certain FERC established emission control criteria or standards;

(3) Case-by-case review of the environmental impact of each qualifying facility;

(4) Limiting qualifying status to certain locations where environmental conditions are not too severe or limiting the density of such facilities in any given area;

(5) Limiting qualifying status to certain areas where the Federal, State, or local agency has expressly applicable environmental permitting requirements, emission standards, or other control measures or otherwise consents to these facilities being qualified, either by rule or on a case-by-case basis;

(6) Altering or reducing the types or extent of benefits available under section 210 to the qualifying facilities; and

(7) Provision for mandatory periodic review and reassessment by the Commission of the environmental impact of the PURPA rules and of the significance of that impact—present and projected—and, if warranted, the suspension, restriction, or prospective denial of further qualifications by the Commission.

The Commission seeks public comment on the possible modifications of the proposed rules described above or any other approach which may be helpful in resolving any environmental questions relating to this program. In addition, the Commission seeks comment on the conclusions reached in the preliminary EA concerning the environmental impacts of the various technologies affected by the Commission's rules.[2]

[2] The Environmental Assessment is available at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C.

Continuation of Environmental Assessment

In addition to solicitation of public comment, the Commission has instructed the Staff to undertake further efforts to quantify the potential extent of risk to the environment from the proposed rules. Additional data will be collected and additional analysis will be performed in keeping with the concerns identified in the preliminary EA. At the end of this process a final Environmental Assessment will be issued.

On the basis of the complete record, the Commission will then make its final determination as to whether its proposed rules will be a major Federal action significantly affecting the quality of the human environment. If the Commission finds that the rules will have no significant effect, than the Commission will proceed forward with these rulemakings in the usual fashion. If the Commission finds that, in some respects, the proposed rules are likely to have significant adverse environmental effects, it may take any of the following actions: (1) promulgate the proposed rules as final insofar as they pose no significant threat to the environment, but withhold promulgation of any part of the rules which would encourage the use of biomass, centralized solar energy systems, a diesel cogeneration, pending preparation of an EIS; (2) promulgate the proposed rules with such modifications as the Commission determines are necessary to assure that the final rules will not significantly affect the environment; or (3) withhold issuance of the final rules pending preparation of an environmental impact statement covering the entire scope of the proposed rules.

Comment Procedure

Any interested person may submit data, views and comments concerning these issues. Such comments should be addressed to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should not be submitted later than December 1, 1979. An original and 14 conformed copies should be filed with the Commission, and should reference Docket No. RM79–55. Comments should indicate the name, title, mailing address, and telephone number of a person to whom communications concerning the proposal may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capital Street, N.E., Washington, D.C., during regular business hours.

Comments received in response to the initial Notice of Proposed Rulemaking are part of the record in this proceeding and will be considered in the determination of the final rule.

In addition, the Commission will conduct public hearings in connection with the Notice of Proposed Rulemaking in Docket No. RM79–55 at which persons desiring to present views on these issues will have an opportunity to do so. The dates and location of these hearings will be announced in the near future.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

¶ 32,041 Discontinuation of the Use of Forms Nos. 3, 3A, 3P, 40, and 82

44 F. R. 61976 (October 29, 1979).

18 CFR Parts 3, 141, and 260

[Docket No. RM80-2]

Discontinuation of the Use of Forms Nos. 3, 3A, 3P, 40, and 82; Proposed Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Notice is hereby given that the Federal Energy Regulatory Commission (Commission) proposes to amend its regulations to discontinue the use of five data collection forms no longer needed by the Commission for its regulatory functions.

DATE: Written comments by November 23, 1979.

ADDRESS: All written comments to reference Docket No. RM80-2 and to be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, 825 North Capitol Street, NE., Room 8113, Washington, D.C. 20426, (202) 357-8079.

October 23, 1979.

I. Background

The Commission is engaged in an ongoing effort to eliminate unnecessary burdens on the industries regulated by it. This rulemaking is part of that effort. All data elements contained in forms submitted to the Commission are being evaluated to determine how many of the data are needed by the Commission to carry out its regulatory functions. Forms which do not produce information needed by the Commission will be eliminated as FERC forms.

The Commission hereby proposes to discontinue Forms Nos. 3, 3A, 3P, 40 and 82 because the data contained therein are no longer necessary for the fulfillment of the Commission's regulatory responsibilities. Form No. 40 expired in July 1976 and the Commission does not need the information previously reported by means of this form. Forms 3, 3A, 3P, and 82 are no longer needed by the Commission due to the changes in its regulatory responsibilities described below.

Forms Nos. 3, 3A, 3P, and 82, were originally promulgated under authority granted to the Federal Power Commission (FPC) (the Commission's predecessor agency) by section 311 of the Federal Power Act (FPA) (49 Stat. 863; 16 U.S.C. 791(a)). That section authorizes investigations and information gathering relating to electric energy. These functions, among others, were transferred to the Secretary of Energy (Secretary) by section 301(b) of the Department of Energy Organization Act [1] (DOE Act) (42 U.S.C. 7101, *et. seq.*). The authority to administer section 311 was in turn delegated by the Secretary to the Energy Information Administration (EIA) [2] and to the Commission to the extent needed to perform its other vested or delegated functions.[3]

As a result of these changes in the Commission's regulatory responsibilities, the Commission has determined that it no longer needs the data collected by means of the four

[1] Section 301(b) provides, generally, that powers vested in the FPC under the FPA and the Natural Gas Act (15 U.S.C. 717) which were not transferred to the Commission by Title IV of the DOE Act are vested in the Secretary.

[2] Department of Energy Delegation Order No. 0204-3, October 1, 1977.

[3] Delegation Order No. 0204-1, October 1, 1977 (42 FR 55607, October 18, 1977).

referenced forms in order to perform its regulatory functions under the provisions of the DOE Act or the delegation order described above.

However, the EIA may determine that collection of some of the data elements included in these forms is necessary in order to discharge its statutory responsibilities. If the EIA should make such a determination, the Commission would issue a final based on this Notice with a delayed effective date. This would provide the EIA (or any other potentially interested agency) a period of time in which to justify the need for and receive Office of Management and Budget (OMB) approval of collection of such data under the agency's own authority.

II. Forms To Be Discontinued

Following is a brief description of each of the forms which we are hereby proposing to eliminate.

Form No. 3—Typical Net Monthly Bills for Electric Service (18 CFR 3.142(a)(27) and 141.21).

Form No. 3 is submitted annually by utilities. The Commission has determined that it does not need the information contained in this form. However, EIA uses the data collected therein to publish a yearly report entitled *Typical Electric Bills*, and therefore, may want to assume sponsorship of this form.

Form No. 3A—All-Electric Homes Data Sheet (No CFR reference) (Expired June 30, 1979).

Form No. 3A is voluntarily filed by electric utilities, and neither EIA nor the Commission presently uses any of the information contained therein.

Form for No. 3P—Residential Electric Bill Data for the U.S. Bureau of Labor Statistics (18 CFR 3.142(a)(48) and 141.28).

Since 1940 the Commission has been supplying the Bureau of Labor Statistics (BLS) with monthly electric bill data collected on Form No. 3P pursuant to the Commission's authority under section 311 of the FPA. This information is now being collected by EIA on EIA Form No. 101 for use by the BLS.

Form No. 40—Natural Gas Companies Annual Report of Proved Domestic Gas Reserves (18 CFR 3.170(a)(31) and 260.13) (Expired July 1976).

Form No. 40 requires certain natural gas companies to supply the Commission with an annual report of proven domestic reserves. On November 22, 1978,[4] the Commission postponed the filing date for Form 40 pending the implementation by EIA of Form No. EIA–23, which would collect the information contained in Form 40. Form No. EIA–23 is now being collected by EIA, and the Commission thus proposes to discontinue the use of Form No. 40.

Form No. 82—Retail Rate Level Change (18 CFR 3.142(a)(43) and 141.27) (Expired June 30, 1978).

Form No. 82 is designed to obtain from all electric utilities within 60 days of the effective date of a new retail rate schedule or change of an existing retail rate schedule the 12-month dollar effect of such change. Neither EIA nor the Commission presently uses any of the information contained therein.

III. Comments Requested

The Commission invites written comments relevant to this proposal. Copies of all comments received will be furnished to the EIA for its use. Thus, it will be helpful if commenters would address the following questions:

1. Do the data in question serve any Commission regulatory functions?

2. If the data do not serve Commission functions, is there, nevertheless, any reason for continued collection of the data by another Federal agency?

Anyone suggesting the continued collection of data which are contained

[4] Order No. 528–E, Docket No. RM74–10, 43 FR 56035, November 30, 1978.

in the forms described above should identify what agency should collect the data, and for what purpose.

IV. Comment Procedures

Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80-2. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, November 23, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

(Department of Energy Organization Act, (42 U.S.C. 7101), *et seq.*, E. O. 12009, 42 FR 46267.)

For the reasons stated above, the Commission proposes to discontinue Form No. 3A, entitled *All-Electric Homes Data Sheet*.

In addition, in consideration of the foregoing, the Commission proposes to amend Parts 3, 141, and 260 of Chapter 1, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 3—ORGANIZATION, OPERATION, INFORMATION AND REQUESTS

§ 3.142 [Amended]

1. Section 3.142 is amended in paragraph (a) by deleting subparagraphs (27), (43), and (48) in their entirety.

§ 3.170 [Amended]

2. Section 3.170 is amended in paragraph (a) by deleting subparagraph (31) in its entirety.

PART 141—STATEMENTS AND REPORTS (SCHEDULES)

§ 141.21 [Deleted]

3. Section 141.21 is deleted in its entirety.

§ 141.27 [Deleted]

4. Section 141.27 is deleted in its entirety.

§ 141.28 [Deleted]

5. Section 141.28 is deleted in its entirety.

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

§ 260.13 [Deleted]

6. Section 260.13 is deleted in its entirety.

¶ 32,042 Interlocking Positions Under Section 211 of the Public Utility Regulatory Policies Act of 1978

44 F. R. 66205 (November 19, 1979).

18 CFR Part 46

[Docket No. RM80-9]

Interlocking Positions Under Section 211 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Notice is hereby given that the Federal Energy Regulatory Commission (Commission) proposed to implement section 211 of the Public Utilities Regulatory Policies Act of 1978 (PURPA) which amends section 305 of the Federal Power Act. This rulemaking proposes reporting requirements for a person holding interlocking positions with a public utility and with any other business entity described in the proposed rulemaking. The Commission also proposes to impose a requirement that each public utility publish a list of its twenty largest purchasers, as mandated by section 211 of PURPA.

DATE: Written comments by December 10, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Reference No. RM80-9.

FOR FURTHER INFORMATION CONTACT: Colette Bohatch, Office of the General Counsel, Regulatory Development Branch, Room 8113, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8079.

Issued: November 14, 1979.

I. Background

This proposed rule, when issued in final form, will implement section 211 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 211 amends section 305 of the Federal Power Act by adding a new subsection (c) which imposes a reporting requirement upon a person holding interlocking positions involving a public utility and any other business entity identified in section 211. The proposed rule, set forth below, describes procedures for reporting by written statement to the Federal Energy Regulatory Commission (Commission) and describes the contents of the written statement.

Certain interlocking positions involving two or more public utilities or a public utility and "any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of a public utility" or "any company supplying electrical equipment to such public utility" are unlawful under subsection (b) of section 305 unless authorized by the Commission. A person desiring to hold such an interlocking position must file an application with the Commission and make a showing that neither public nor private interests will be adversely affected.

Section 305, as amended by section 211, contains a new subsection (c) which imposes reporting requirements upon a larger class of persons than encompassed by subsection (b), both in terms of the categories of interlocking positions and categories of business entities. Positions within the purview of section 305(c) are officer and director of a public utility and officer, director, partner, appointee, and representative of any business entity listed therein, including another public utility. The business entities within the scope of section 305(c) are the following entities, when interlocked with a public utility:

(1) Any other public utility;

(2) Any bank, trust company, banking association, or any company, firm, or organization that is authorized by law to underwrite or participate in the marketing of securities of a public utility;

(3) Any investment bank, bank holding company, foreign bank or subsidiary thereof doing business in the United States, insurance company, or any other organization primarily engaged in the business of providing financial services or credit, a mutual savings bank, or a savings and loan association;

(4) Any company, firm, or organization which produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel, or other fuel, for the use of any public utility;

(5) Any company, firm, or organization which during any one of the three (3) calendar years immediately preceding the filing date was one of the twenty (20) purchasers of electric energy which purchased (for purposes other than for resale) one of the twenty (20) largest annual amounts of electric energy sold by such public utility (or by any public utility which is part of the same holding company system) during any one of such three (3) calendar years; and

(6) Any company, firm, or organization which is controlled by any company, firm, or organization listed above.

The proposed rule, when issued in final form, requires a written statement be filed with the Commission by a director or an officer of a public utility who, also, holds an interlocking position, as described in the rule, with any of the above business entities. Although the statute gives the Commission a measure of latitude in propounding reporting requirements, the Commission proposes to impose a minimum of requirements for purposes of public comment on this notice of proposed rulemaking.

In addition to the reporting requirements, this proposed rule, when issued in final form, will implement the section 305(c) mandate that each public utility publish on or before January 31 of each year, commencing in 1980, a list of the purchasers who purchased (for purposes other than for resale) one of the twenty (20) largest annual amounts of electric energy during any one of the three (3) years immediately preceding the publication date.

II. Issues for Comment

The Commission requests comments from the public specifically with regard to several sections of the proposed rule.

Section 46.3 identifies those who must report. Paragraph (a) concerns a director or an officer, including any person who performs any similar duties or functions, in a public utility. Paragraph (b) concerns these same positions held in any business entity described in § 46.4 *and* further includes partner, appointee, and representative of such business entity. The Commission understands these terms to include, for example, the following: persons who are appointed on a temporary or permanent basis to perform the duties or functions ordinarily performed by a director or an officer; and persons who act as representatives, such as consultants, of a business entity interlocked with a public utility. With an objective of further refining § 46.3, the Commission requests comments on paragraphs (a) and (b) specifically discussing the terms "appointee" and "representative."

In addition, several definitions require special consideration by the public. "Controlled" is used in section 305(c)(2)(F) in the following context: "any company, firm, or organization which is controlled by any company, firm, or organization" listed in section 305(c). Although "control" is defined qualitatively by § 46.2(b), the Commission believes that the definition should set forth quantitative parameters in order to better serve the intent of Congress as articulated in the Statement of Managers.[1]

[1] The definition of the word "controlled" in paragraph (2)(F) of new subsection (c) is, the conferees intend, to be defined by the Commission. The conferees were reluctant to establish a single arbitrary percentage of stock ownership as the yardstick for measuring control. Rather, it is anticipated that after appropriate consideration the Commission will arrive at a definition that

[1] Conf. Rep. No. 95-1750, p. 98.

takes into account the nature and extent of control of one firm by another.

Before incorporating quantitative parameters, however, the Commission requests comments regarding the definition of "control" with the above discussion as a guide to the nature of comments solicited. The Commission is interested particularly in public comment on parameters setting out the kind of control and level of control.

Also, "electrical equipment" is defined in § 46.2(d) to describe the term as it is used in section 305(c). The definition, by footnote, cites sections of the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Part 101, Subchapter C, Chapter I, Title 18 of the Code of Federal Regulations to serve as examples. The Commission similarly requests comments on this definition.

Finally, this proposed rulemaking requires disclosure by a reporting person of his interest in, and compensation from, a § 46.4 business entity to the extent that either exceeds $10,000. Comments are sought as to the appropriateness of this amount.

III. Comment Procedures

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should reference Docket No. RM80-8. An original and fourteen (14) copies should be filed. All comments received prior to 4:30 p.m. E.S.T., December 10, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established for this rulemaking and which is available for public inspection during regular business hours in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

(Federal Power Act, as amended, 16 U.S.C. 792–828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; Department of Energy Organization Act, 42 U.S.C. 7101–7352)

In consideration of the foregoing, the Commission proposes to add Part 46 to Subchapter B, Chapter I, Title 18 Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

Subchapter B is amended by adding the following new Part 46 after Part 45:

PART 46—WRITTEN STATEMENT REQUIREMENTS FOR PERSONS HOLDING INTERLOCKING POSITIONS

Sec.

46.1 Purpose.
46.2 Definitions.
46.3 General rule.
46.4 Business entities under this part.
46.5 Contents and procedures for filing the written statement.
46.6 Identification of the twenty largest purchasers.

Authority: This part issued under the Federal Power Act, as amended, 16 U.S.C. 792 828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; Department of Energy Organization Act, 42 U.S.C. 7101–7352.

§ 46.1 Purpose.

The purpose of this part is to monitor interlocking positions involving public utilities and certain other business entities described in this part for purposes of implementing section 305(c) of the Federal Power Act as amended by section 211 of the Public Utility Regulatory Policies Act of 1978.

§ 46.2 Definitions.

For the purpose of this part:

(a) "Public utility" has the same definition as that used in section 201(e) of the Federal Power Act.

(b) "Control" (including the term "controlled") means the possession, directly or indirectly, of the power to

direct management or policies of a business entity whether such power is exercised through one or more intermediary companies or pursuant to an agreement, written or oral, and whether such power is established through ownership or voting of securities, common directors, officers, or stockholders, voting trusts, holding trusts, associated business entities, contract, or any other direct or indirect means.

(c) "Business entity" means any firm, company, or organization including any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing and any parent and subsidiary of any corporation but does not include "municipalities" as defined in the Federal Power Act (section 3, 49 Stat. 838, 16 U.S.C. 296).

(d) "Electrical equipment" is any apparatus or device, or component part thereof, that is used in a function which is either mechanically or by legal prescription necessary to the process of generating, transmitting, or distributing electrical energy, including any electrically powered or electronic apparatus or device, or component part thereof, that is directly used in connection with the process of generating, transmitting, or distributing electrical energy.[1]

§ 46.3 General rule.

A person must file a written statement in accordance with this part if he:

(a) Serves as a director or a Chief Executive Officer, President, Vice President, Secretary, Treasurer, General Manager, Comptroller, Chief Purchasing Agent, or performs any other similar duties or functions, in a public utility; and

(b) Serves in any of the positions described in paragraph (a) for a business entity identified in § 46.4 or is a partner, appointee, or representative of any such business entity.

§ 46.4 Business entities under this part.

Business entities within the purview of section 305(c) of the Act are the following:

(a) Any investment bank, bank holding company, foreign bank or subsidiary thereof doing business in the United States, insurance company, or any other organization primarily engaged in the business of providing financial services or credit, a mutual savings bank, or a savings and loan association;

(b) Any business entity authorized by law to underwrite or participate in the marketing of securities of public utilities;

(c) Any business entity which produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel or other fuel for the use of any public utility;

(d) Any business entity which during any one of the three (3) calendar years immediately preceding the filing date was one of the twenty (20) purchasers of electric energy which purchased (for purposes other than for resale) one of the twenty (20) largest annual amounts of electric energy measured in kilowatt hours sold by such public utility (or by any public utility which is part of the same holding company system) during any one of such three (3) calendar years;

[1] This definition includes, but is not limited to, those items (with the exception of vehicles, structures, foundations, settings, services and other non-equipment items such as permit and inspection costs) in the following accounts described in Part 101, Title 18 of the Code of Federal Regulations: Boiler/Reactor plant equipment (Accounts 312 and 322); Engines and engine driven generators (313); Turbogenerator units (314 and 323); Accessory electrical equipment (315, 324, 334 and 345); Miscellaneous power plant equipment (316, 325, 335 and 344); Water wheels, turbines and generators (333); Fuel holders, producers, and accessories (342); Prime movers (343); Generators (344); Station equipment (353 and 362); Poles, towers and fixtures (354, 355 and 364); Overhead conductors and devices (356 and 365); Underground conduit (357 and 366); Underground conductors and devices (358 and 367); Storage battery equipment (363); Line transformers (368); Services (369); Meters (370); Installation on customer's premises (371); Street lighting and signal systems (373); and Communication equipment (397).

(e) Any business entity referred to in subsection (b) of section 305 of the Federal Power Act; and

(f) Any business entity which is controlled by any business entity described or referred to in this section.

§ 46.5 Contents and procedures for filing the written statement.

(a) Each written statement shall provide the following information:

(1) Full name, business address, and place of residence of the person reporting;

(2) Name and principal place of business of each of the business entities described in § 46.4 in which the person holds an interlocking position; the interlocking positions held and the duties and functions pertinent to each position; and a brief description of the nature of the business relationship, if any, between a public utility and the subject entity, (*e.g.*, equipment supplier, securities underwriter, creditor, fuel supplier, and major purchaser of electricity); and

(3) The nature of any interest (*e.g.*, stock ownership, partnership, and annuity) and the basis for any compensation to the person (*e.g.*, dividends, salary, and fees for services rendered) if the amount of interest in or compensation received from an entity listed in § 46.4 exceeds $10,000 in the preceding calendar year.

(b) The written statement shall be filed with the Commission on or before April 30 of each year immediately following the calendar year in which the person held, for any part of the calendar year the interlocking positions. An original and two (2) copies of each written statement shall be filed with the Commission. Each original shall be dated, signed by the person, and verified under oath in accordance with § 1.31.60 of this chapter. Each copy shall bear the date and signature that appeared on the original and shall be complete in itself, but the signature on the copies may be stamped or typed and the notarial seal may be omitted. Such statement shall be available to the public through the Commission's Office of Public Information.

§ 46.6 Identification of the twenty largest purchasers.

(a) On or before January 31 of each calendar year, each public utility shall identify purchasers who have purchased (for purposes other than for resale) from the public utility the twenty (20) largest annual amounts of electric energy measured in kilowatt hours in each one of the three (3) calendar years immediately preceding each January 31.

(b) Each public utility shall file with the Commission by January 31 of each year the list of purchasers identified under paragraph (a). The list shall contain the following information for each purchaser:

(1) Name and address of the purchaser; and

(2) Total kilowatt hours of electric energy purchased by the purchaser during the subject year.

(c) Each public utility shall notify by January 31 of each year each purchaser which has been identified under paragraph (a).

¶ 32,043 Regulation of Natural Gas Sales Under the Natural Gas Policy Act of 1978

44 F. R. 66208 (November 19, 1979).

18 CFR Part 277

[Docket No. RM80-8]

Regulation of Natural Gas Sales Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The proposed rule would implement sections 315(b) and 315(c) of the Natural Gas Policy Act of 1978 (NGPA). Section 315(b) establishes that the purchaser of natural gas which is subject to deregulation under section 601(a)(1)(B) of the NGPA has the right to a bona fide offer to buy such natural gas and the right of first refusal to buy such natural gas under the terms of an offer made by the purchaser and accepted by a third party. The proposed rule in section 315(b) establishes the procedures by which the requirements of the bona fide offer and right of first refusal shall be satisfied. Under the authority granted in section 315(c), the Commission has prescribed record keeping requirements pertaining to sales of natural gas under section 315 of the NGPA.

DATES: Written comments are due December 19, 1979. Public Hearing December 14, 1979; requests to participate by December 6, 1979.

ADDRESSES: Send comments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 9310, Washington, D.C. 20426. Request to participate should be sent to the same location. The location and room designation of the hearing will be specified at a later date.

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Office of the General Counsel, Room 8000, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8455.

Bona Fide Offers; Right of First Refusal; Notice of Proposed Rulemaking and Public Hearing

November 14, 1979.

Background

This proposed rule would implement section 315(b) of the Natural Gas Policy Act of 1978 ("NGPA"). The statute imposes the duty upon a seller to make a bona fide offer for the continued sale of certain categories of deregulated natural gas upon the expiration of the contract. If the bona fide offer is rejected, the statute creates a right of first refusal which permits the original purchaser to match the terms of any third party offer to purchase the natural gas.

Under the Natural Gas Act (NGA), natural gas became dedicated to interstate commerce upon the commencement of sales for resale in interstate commerce. Once the natural gas was dedicated, its sale could not be terminated until the seller had obtained abandonment authorization from the Commission under section 7(b) of the NGA. Frequently, producers would sell natural gas under limited term contracts. However, even if the sales contract covering the dedicated volumes expired or terminated, the gas had to continue to flow in interstate commerce absent abandonment authorization.

Section 601(a)(1)(B) of the NGPA exempts from NGA regulation natural gas which was committed or dedicated to interstate commerce on November 8, 1978, if a final determination has been made by a jurisdictional agency that the natural gas qualifies as:

(1) High-cost natural gas (section 107(c) (1), (2), (3), and (4));
(2) New natural gas (section 102(c)); or
(3) New onshore production gas. (section 103(c)).

However, the seller in any first sale of natural gas which qualifies for deregulation under section 601(a)(1)(B) (except certain Outer Continental Shelf ("OCS") gas) must comply with the bona fide offer/right of first refusal requirements of Section 315(b). The bona fide offer/right of first refusal does not apply to natural gas committed or dedicated to interstate commerce solely because it is produced from the Outer Continental Shelf (section 2(18)(A) (i) natural gas). In either case, the transportation of OCS gas remains subject to the Commission's transportation certificate authority under section 7(c) of the Natural Gas Act. Section 315(b) requirements do apply to OCS gas which comes within the scope of both sections 2(18)(A) (i) and (ii).

Section 315(b) assures to a degree, that natural gas supplies will continue to flow to the interstate market despite the removal of certain categories of natural gas from the abandonment jurisdiction of the Commission under the Natural Gas Act. Section 315(b) requires the seller to make a bona fide offer to the original purchaser, that is, the purchaser who was entitled to receive the natural gas under section 2(18)(A)(ii) of the NGPA on November 8, 1978, or his successor. The section further grants the original purchaser the right of first refusal of the first offer to sell such natural gas which offer has been substantially accepted in principle by another party in an arms-length transaction. The bona fide offer must be made every time the contract with the original purchaser expires or terminates. If the bona fide offer is rejected, the original purchaser's right of first refusal arises. In other words, the bona fide offer and right of first refusal flow with the natural gas for as long as the original purchaser continues to be the purchaser of the natural gas. Assume a contract was formed as a result of negotiation between the seller and original purchaser, but the negotiations had followed a rejection of a bona fide offer and preceded offer substantially accepted in principle with a third party and presented to the original purchaser for exercise of its right of first refusal. Then the right of first refusal would arise upon termination of the contract negotiated following rejection of the bona fide offer. This interpretation assures an original purchaser, who is willing to meet market conditions, continued access to the natural gas. The Commission believes this result is essential to meet the legislative intent of section 315(b). With a contrary interpretation of section 315(b), the seller could eliminate the obligations concerning the right of first refusal by accepting a counter offer to the bona fide offer.

A. Bona Fide Offers

The statute does not define a bona fide offer. According to the Statement of Managers, however, at the minimum, it must contain terms a purchaser could lawfully accept under the Natural Gas Act.[1] However, the intent of section 601(a)(1)(B) is deregulation of nonprice terms except that the Commission has specifically been granted authority to prescribe minimum contract duration for section 601(a)(1)(B) natural gas. See, section 315(a). In light of these provisions, the Commission does not believe it is proper to prescribe the precise terms and conditions of the bona fide offer required under section 315(b).

B. Right of First Refusal

The statute provides that an offer for the first sale of these certain categories of natural gas which has been substantially accepted in principle by another person in an arms-length transaction must be offered to the original purchaser. If the original purchaser is willing to meet the terms and conditions of the offer accepted by the third party, the original purchaser shall be entitled to purchase such natural gas.

The statute requires that the offer substantially accepted in principle by a third party in an arms-length transaction

[1] H. Report No. 95-1752, 95th Cong. 2d Sess. at 111 (1978).

be presented to the original purchaser for the right of first refusal. In implementing this provision, the Commission must balance the interests of both the original purchaser and the seller, which Congress intended to protect. As stated previously, section 601(a)(1)(B) indicates Congress wished to remove the gas from non-price regulation under the Natural Gas Act. As a result, the seller, by negotiating an arms-length transaction may negotiate a sale which reflects the economic conditions of the market place—up to the maximum price per MMBtu established by Title I. However, Congress was also concerned that pipeline (original) purchasers, which made advanced payments or invested capital in facilities to receive gas, relying on the NGA which provided that such gas was committed and dedicated to them until abandonment, have an opportunity to continue to purchase such natural gas if they are willing to meet the economic market conditions for the purchase of such natural gas. It is possible that an offer substantially accepted by a third party may contain conditions—e.g., delivery point, pressure and rate of take—which the original purchaser would be unable to accept because of situations prevailing on its own system or those of its customers. Thus, the Commission believes that the right of first refusal should allow the original purchaser who accepts the "offer substantially accepted in principle by a third party" to receive the natural gas at the delivery point and under the physical conditions of delivery specified in the previous contract with the original purchaser.

It is possible that some natural gas which would be subject to this subpart has been sold to third parties in the absence of a Commission rule under section 315(b) of the NGPA. To the extent such sales have been made the Commission intends to allow the original purchaser to seek appropriate relief from the Commission. See § 277.208.

The Commission intends to make this regulation effective as of the date the proposed rule is issued, except in those cases where the purchaser has waived his rights under § 315(b) of the NGPA, or where the seller can establish substantial compliance with the provisions of § 315(b) which the Commission's rule must implement.

Summary of Proposed Regulation

§ *277.201.* The purpose of Subpart B of Part 277 is to implement section 315(b) of the NGPA concerning bona fide offers and rights of first refusal.

§ *277.202.* This subpart would apply only to natural gas (1) which was committed or dedicated to interstate commerce on November 8, 1978 under section 2(18)(A)(ii) of the NGPA; (2) for which a final determination has been made by a jurisdictional agency that the natural gas is high cost natural gas under section 107, new natural gas under section 102 or new, onshore production under section 103; and (3) which would be subject to the Natural Gas Act but for the provisions of section 601(a)(1)(B) of the NGPA. However, the requirements of this subpart would not apply to natural gas committed or dedicated to interstate commerce solely because it is OCS gas.

§ *277.203.* The definition of "subject contract" reflects the variety of circumstances which result in natural gas being "committed or dedicated to interstate commerce" by reason of section 2(18)(A)(II). First, any gas purchase contract between the seller and the original purchaser (unless there has been a lawful intervening sale to a third party) is a "subject contract." Second, even if no gas purchase contract presently covers the natural gas after the effective date of section 601(a)(1)(B), an earlier contract could still qualify as a subject contract. Finally, the flow of natural gas in interstate commerce without a purchase contract can result in a service obligation under the Natural Gas Act and render the natural gas "committed or dedicated to interstate commerce." In such a case, the contract implied in law between the seller and the purchaser is a subject contract. Any contract which implied in law arises

after the termination date of a subject contract as a result of the requirements of § 277.207 is excluded from the definition.

The definition of "expiration date of a subject contract" is defined as the expiration or termination date of the contract. In addition, in the case of an implied contract arising from a Natural Gas Act service obligation, the date of the final determination which removes the obligation by operation of section 601(a)(1)(B) is defined as being the expiration date.

The "original purchaser" is the beneficiary of the rights afforded by section 315. The definition incorporates by reference case law under the Natural Gas Act which determines which person would be entitled to receive the natural gas.

§ *277.204.* This section of Subpart B would prohibit the sale of natural gas which is subject to this subpart in a first sale to a third person until the bona fide offer and right of first refusal obligations have been met. Once the original purchaser has rejected both the bona fide offer and the offer substantially accepted in principle, the seller's obligations under section 315 would be satisfied.

§ *277.205. Bona Fide Offer.* The proposed rule requires that the seller make a bona fide offer to the original purchaser. Until such a bona fide offer is made, the natural gas must continue to be sold to the original purchaser.

The bona fide offer must be made, during the time frame established, upon the expiration or termination of the original contract for sale of natural gas between the seller and original purchaser, or any subsequent contract between the seller and the original purchaser or a successor in interest thereto.

Where a final determination has been made that natural gas qualifies for this subpart at least 45 days before the contract (other than a contract implied in law) expires or terminates, the proposed rule would require that the bona fide offer for the sale of the natural gas be made no later than 20 days before expiration of the contract. In all other cases—where final determination is made less than 45 days prior to expiration or termination of the contract or the contract is a contract implied in law—the bona fide offer would have to be made within 20 days after the final determination. See § 277.205(b). The Commission recognizes that there will be cases where a final determination is not made simultaneously on all the dedicated acreage covered by the subject contract. However, because the 20 days is only an outside time limit, a single bona fide offer may be made which covers all wells for which a determination has been made as well as those for which a final determination may be made subsequently. Thus, sellers are not required to make bona fide offers every time a well, not subject to an existing contract, is determined to qualify as new natural gas, high cost natural gas or new, onshore production.

The bona fide offer, § 277.203(b), would be required, at the minimum, to meet the terms and conditions which the interstate pipeline (original purchaser) could accept under the Natural Gas Act. Moreover, the bona fide offer must be sufficiently definite that if it is accepted by the original purchaser, it will result in a contract binding on both the seller and the purchaser. The Commission believes that a less firm offer would not achieve the statutory purpose—an opportunity for the original purchaser to enter into a contract to continue to purchase the natural gas. Other requirements for bona fide offers, e.g., how made and how accepted or rejected, are set forth in proposed § 277.205(c).

§ *277.206. Right of first refusal.* As stated above, the proposed rule provides that the right of first refusal runs with the natural gas until such time as the natural gas has been sold to a third party by virtue of the original purchaser's failure to exercise its right of first refusal. See proposed § 277.206(b).

Proposed paragraph (b) of § 277.206 requires that the offer subject to the right of first refusal shall be made when the offer has been substantially

accepted in principle by another person in an arms-length transaction. However, offers made prior to the rejection of a bona fide offer would not trigger this statutory right. The seller would not be required to find a third party purchaser. Rather, the seller could decide to shut-in the production, or to take the natural gas for its own use.

An offer substantially accepted in principle is defined in proposed § 277.203(g). It requires a written offer to sell natural gas and written acceptance thereof. The offer must be sufficiently firm that a binding contract with the new purchaser will result if the right of first refusal is not exercised. Unlike the bona fide offer, the offer substantially accepted in principle would not be required to meet the minimum requirements of the Natural Gas Act.

Other procedural requirements governing the right of first refusal are found in proposed paragraph (c) of § 277.205.

Proposed paragraph (d) would allow the original purchaser to accept an offer substantially accepted in principle without changing the delivery point for the natural gas. In many cases, the seller and a third party will agree to a defferent delivery point with corresponding changes in delivery pressures. However, in the Commission's view, the original purchaser would retain the right to receive the natural gas at the delivery point specified in the subject contract.

§ 277.207 Interim protective sales. Proposed § 277.207 requires that gas subject to section 315(b) of the NGPA which was produced and sold on December 1, 1978, must continue to flow to the original purchaser until the bona fide offer requirements of § 277.205 have been fulfilled, unless the natural gas has been subsequently sold to a third party purchaser. Such gas is to be sold under the terms and conditions existing in the contract on the last day the contract was in effect. Thereafter, pending exercise of right of first refusal—that time during which the seller may be negotiating a third party offer substantially accepted in principle—the seller could either negotiate an interim sale with the original purchaser, at a price accceptable to both parties, or shut-in the natural gas. The Commission recognizes that those sellers subject to this subpart and which are not producers may not have the ability to discontinue sales pending resolution of negotiations with a third party. To the extent this proposed rule causes a person special hardship, inequity, or unfair distribution of burdens, the person may seek an adjustment to the regulations, pursuant to section 502(c) of the NGPA.

§ *277.208 Intervening third party sales.* When the seller and a third party purchaser have entered into a contract to sell natural gas subject to this subpart, prior to the effective date of the final rule, the bona fide offer/right of first refusal requirements are deferred until the contract with the third party expires or is terminated. In addition, the original purchaser may seek other relief from the Commission.

Other provisions. The Commission recognizes that this proposed rule may be particularly troublesome to a captive seller— one whose production is connected only to the facilities of the original purchaser. The proposed rule allows the bona fide officer to be made at any time, including a time significantly prior to the expiration of the contract with the original purchaser. The original purchaser has 20 days from presentation to accept or reject the bona fide offer. At any time after rejection of the bona fide offer, the offer for first refusal may be presented. Therefore, a captive seller could negotiate the contracts in sufficient time to allow for new facilities of a third purchaser to be in place at expiration of the contract with the original purchaser which has chosen not to enter into a new contract with the seller.

Section 315(b) is intended, in part, to protect the ability of the original purchaser to continue to purchase the natural gas previously committed or dedicated to it. If an original purchaser determines such supplies are not necessary or is otherwise not interested in continuing to purchase such natural

gas, the Commission believes the original purchaser should be entitled to waive its rights under section 315(b). Waiver would release the seller from unnecessary obligation under this subpart. Proposed § 277.209 so provides.

In lieu of exercising its right to require the filing of contracts, as allowed in section 315(c) of the NGPA, the Commission proposes to prescribe a record keeping requirement, propose § 277.210. It assures availability of records necessary for determination of compliance with section 315(b).

Written Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received within 30 days of publication of this notice in the Federal Register will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public information, 825 North Capitol Street, N.E., Washington, D.C. during regular business hours. Comments should be submitted to the Federal Energy Regulatory commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80–8.

Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on December 14, 1979, beginning at 9:30 a.m., and will continue if necessary on the following day. A hearing room will be designated on December 10, 1979, and will be posted in the Office of Public Information, Room 1000. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., December 6, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM80–8, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m., on December 10, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 20 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. § 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend (effective November 14, 1979) Part 277, Subchapter H, Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Part 277 is amended by adding a Table of Contents to read as follows:

PART 277—OTHER PROVISIONS

Subpart A—Contract Duration

Sec.
277.101 Duration of new contracts for first sale of certain OCS gas.

Subpart B—Bona Fide Offers; Right of First Refusal

277.201 Purpose.
277.202 Applicability.
277.203 Definitions.
277.204 General rule.
277.205 Bona fide offers.
277.206 Right of first refusal.
277.207 Interim protective sales.
277.208 Intervening third party sales.
277.209 Waiver of rights under this subpart.
277.210 Recordkeeping requirements.

Authority: This part is issued under the Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301, et seq. [formerly cited as Pub. L. 95-621, 92 Stat. 3350].

2. Part 277 is further amended in the text of the regulations by adding the title *Subpart A—Contract Duration* immediately preceding the text of § 277.101.

3. Part 277 is further amended by adding a new Subpart B to read as follows:

Subpart B—Bona Fide Offers; Right of First Refusal

§ 277.201 Purpose.

The purpose of this subpart is to implement section 315(b) of the NGPA. This subpart requires a seller, prior to making a first sale of certain categories of natural gas to a person other than the original purchaser:

(a) To make a bona fide offer to sell natural gas to the original purchaser; and

(b) Upon rejection of a bona fide offer or upon expiration or termination of any contract for the sale of natural gas subject to this subpart, to give the original purchaser the right of first refusal of the first offer to sell such natural gas, if such offer has been substantially accepted in principle by another person in an arms-length transaction.

§ 277.202 Applicability.

(a) Except as provided in paragraph (b) of this section, this subpart applies to natural gas which:

(1) Was committed or dedicated to interstate commerce on November 8, 1978; and

(2) Has been determined to be high-cost natural gas, or new natural gas or natural gas produced from any new onshore production well; and

(3) Would be subject to the provisions of the Natural Gas Act and the jurisdiction of the Commission thereunder but for the provisions of section 601(a)(1)(B) of the NGPA; and

(4) Is produced on or after December 1, 1978.

(b) This subpart does not apply to any natural gas committed or dedicated to interstate commerce solely by reason of its being natural gas from the OCS under section 2(18)(A)(i) of the NGPA.

§ 277.203 Definitions.

For purposes of this subpart:

(a) "Arms-length transaction" means a transaction between parties with adverse economic interests. Arms-length transactions exclude transactions between affiliates or family members.

(b) "Bona fide offer" means a written offer by the seller to the original purchaser which would be legal for such purchaser to accept under the Natural Gas Act and which is sufficiently firm that if accepted by the original purchaser would result in a binding contract enforceable by the seller and the purchaser.

(c) "Final determination" means an eligibility determination which has become final within the meaning of § 273.102(b) of this chapter.

(d) "High-cost natural gas" means natural gas for which there has been a final determination by a jurisdictional agency, in accordance with Parts 274 and 275 of this chapter that it is high cost natural gas described in section 107(c)(1), (2), (3) or (4) of the NGPA.

(e) "Natural gas produced from any new, onshore production well" means natural gas for which there has been a final determination by a jurisdictional agency, in accordance with Parts 274

and 275 of this chapter, that it is produced from any new, onshore production well described in section 103(c) of the NGPA.

(f) "New natural gas" means natural gas for which there has been a final determination by a jurisdictional agency, in accordance with Parts 274 and 275 of this chapter, that it is new natural gas described in section 102(c) of the NGPA.

(g) "Offer substantially accepted in principle" means a written acceptance by a purchaser (other than the original purchaser) of a written offer to sell the natural gas. The written offer and acceptance must be:

(1) Subject to the right of first refusal; and

(2) Sufficiently firm such that if the original purchaser rejects the written offer, the written offer and acceptance by a purchaser (other than the original purchaser) would result in a contract which is binding on the seller and that purchaser.

(h) "Subject contract" means a contract for the sale of natural gas subject to this subpart which:

(1) Was in effect on or after December 1, 1978; and

(2)(i) Is between the seller and the original purchaser unless there has been an intervening sale to a third party which followed the rejection of a bona fide offer and a rejection by the original purchaser of an offer substantially accepted in principle in accordance with § 277.206(d); or

(ii) Is implied in law as arising from the seller's service obligation under the Natural Gas Act (excluding any interim service obligation arising from this subpart or section 315 of the NGPA).

(i) "Expiration date of a subject contract" means:

(1) In the case of a contract implied in law, the date of a final determination that the natural gas covered by the subject contract qualifies as high cost natural gas, natural gas produced from any new, onshore production well, or new natural gas;

(2) In all other cases, the expiration or termination date of the subject contract.

(j) "Original purchaser" means the person who would be entitled to receive natural gas under the Natural Gas Act but for the provisions of section 601(a)(1)(B) of the NGPA. (The original purchaser may be a successor in interest to the person which had the right to receive the natural gas on November 8, 1978).

(k) "Third party purchaser" means a person that purchases the natural gas subject to this subpart from the seller, who has economic interests adverse from those of the seller and who is not:

(i) The original purchaser, or

(ii) An affiliate of the seller, or

(iii) A member of the seller's family.

§ 277.204 General rule.

(a) Except as provided in § 277.208, no seller shall make a first sale of natural gas subject to this subpart to any purchaser other than the original purchaser until the original purchaser has both rejected a bona fide offer in accordance with § 277.205(c) and has rejected an offer substantially accepted in principle in accordance with § 277.206(c).

(b) Once the original purchaser has both rejected a bona fide offer in accordance with § 277.205(c) and has rejected an offer substantially accepted in principle in accordance with § 277.206(c), and the sale to a third party purchaser has been made under the offer substantially accepted in principle and rejected by the original purchaser, the requirements of this subpart no longer apply to the first sale of the natural gas.

§ 277.205 Bona fide offers.

(a) *General rule.* Except as provided in § 277.208, deliveries of natural gas to an original purchaser under a subject contract may not be discontinued unless a bona fide offer which complies with this section has been rejected by the original purchaser under paragraph (c) of this section.

(b) *Time for making the bona fide offer.* (1) *Determination more than 45 days before contract expiration.* With respect to the natural gas subject to this subpart and for which the final

determination that the natural gas qualifies as high-cost natural gas, new natural gas or new, onshore production was made 45 days or more before the expiration date of the subject contract (other than a contract implied in law) the bona fide offer shall be made no later than 20 days prior to the expiration date of the subject contract.

(2) *Determination less than 45 days before contract expiration.* In all other cases, the offer shall be made no later than 20 days after a final determination is made that the natural gas qualifies as high-cost natural gas, new natural gas or natural gas produced from any new, onshore production well.

(c) *Offer; acceptance; rejection.* The written bona fide offer shall be made by sending it to the original purchaser by U.S. mail, certified, and return receipt requested. The original purchaser shall have 20 days from receipt to accept the bona fide offer. The bona fide offer shall be rejected by a written refusal to accept it. Any counteroffer to the bona fide offer made by the original purchaser shall constitute a rejection of the bona fide offer. If the bona fide offer is not accepted or rejected within 20 days, it shall be deemed rejected. The bona fide offer, if accepted, shall be accepted in writing. It shall be deemed accepted when signed and placed in the U.S. mail, certified, return receipt requested.

§ 277.206 Right of first refusal.

(a) *General rule.* The seller shall present any offer substantially accepted in principle by a third person in an arms-length transaction to the original purchaser for exercise of its right of first refusal. The offer shall be presented in accordance with the provisions of this section.

(b) *Time for making the offer.* Except as provided in § 277.208, the seller shall present the offer described in paragraph (a) of this section to the original purchaser, for the exercise of its right of first refusal at the later of:

(1) The time when the offer is substantially accepted in principle; or

(2) The time when the bona fide offer is rejected.

(c) *Offer; acceptance; rejection.* The offer described in paragraph (b) of this section shall be made by sending it to the original purchaser by U.S. mail, certified, return receipt requested. The original purchaser shall have 20 days from receipt to accept the offer. The offer shall be rejected by a written refusal to accept it. Any counteroffer to the offer made by the original purchaser, except as provided in paragraph (d) of this section, shall constitute a rejection. If the offer is not accepted or rejected within 20 days, it shall be deemed rejected. The offer, if accepted, shall be accepted in writing. It shall be deemed accepted when it is signed and placed in the U.S. mail, certified, return receipt requested.

(d) *Delivery point under an accepted offer.* Notwithstanding any contrary provision of an offer substantially accepted in principle, the original purchaser that accepts the offer shall (at its option) have the right to receive the natural gas at the delivery point and under the physical conditions of delivery specified in the subject contract.

§ 277.207 Interim protective sales.

(a) *General rule.* Except as provided in § 277.208, after the expiration date of a subject contract, any natural gas subject to the provisions of this subpart shall continue to be sold to the original purchaser until the requirements of § 277.205 (concerning bona fide offers) have been met.

(b) *Conditions of sale.* Natural gas sold to the original purchaser under paragraph (a) of this section shall be sold under the terms and conditions prevailing in the subject contract on the last day the contract was in effect, except that the seller may charge no more than the price paid by the original purchaser on the day before the final determination was made.

§ 277.208 Intervening third party sales.

(a) *Applicability.* This section applies to natural gas to which this subpart applies if:

(1) The applicable subject contract has expired, and

(2) Such gas is covered by a first sale contract between the seller and a third party purchaser, entered into after the final determination and prior to the date this rule was issued as a proposed rule.

(b) *Relief.* The original purchaser may apply not later than January 15, 1980, to the Commission for such relief as the Commission may determine appropriate.

§ 277.209 Waiver of rights under this subpart.

(a) *General rule.* The original purchaser may voluntarily waive its right to a bona fide offer under § 277.205 or its right of first refusal under § 277.206 or both rights.

(b) *Method of waiver.* Waiver under paragraph (a) of this section must be in writing and signed by the original purchaser.

§ 277.210 Recordkeeping requirements.

All sellers of natural gas which is subject to this subpart must retain copies of all bona fide offers under § 277.205 and offers to the original purchasers to satisfy the original purchaser's right of first refusal under § 277.206. The sellers and purchasers of natural gas which is subject to this subpart must also retain all other documents created in the ordinary course of business and which relate to this subpart.

¶ 32,044 Pricing of Pipeline and Affiliate Production Under the Natural Gas Act

44 F. R. 66613 (November 20, 1979).

[18 CFR Parts 2, 154, and 270]

[Docket No. RM80-6]

Pricing of Pipeline and Affiliate Production Under the Natural Gas Act

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission is proposing to amend its regulations governing the cost component under the Natural Gas Act (NGA) for certain production by interstate pipelines and their affiliates which does not qualify for first sale treatment under the Natural Gas Policy Act (NGPA). In general, production previously allowed the area or nationwide rates under the NGA would be priced by reference to NGPA maximum lawful prices and could be included in the pipeline's PGA clause.

DATES: Public hearing January 7, 1980, 10:00 a.m. Requests to participate by December 28, 1979. Written comments by January 14, 1980.

ADDRESSES: Public hearing in Hearing Room A, Federal Energy Regulatory Commission, Washington, D.C. Send comments and requests to participate in public hearing to Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Reference Docket No. RM80-6.

FOR FURTHER INFORMATION CONTACT:

Eli Farrah, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4008-E, 825 North Capitol Street, NE., Washington, D.C. 20426, (202)357-8316.

Jane Phillips, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8104-B, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8033.

November 14, 1979.

I. Background

The Federal Energy Regulatory Commission (Commission) has issued in final form § 270.203 of its regulations which implements section 2(21) of the Natural Gas Policy Act of 1978 (NGPA). Section 270.203 controls which sales by a pipeline, distributor or affiliate thereof will be considered first sales under the NGPA and thus subject to NGPA Title I prices. Interstate pipeline production which does not qualify for first sale treatment under the NGPA is subject to continuing regulation under the Natural Gas Act (NGA).

Under § 270.203 of the Commission's final regulations concerning pipeline production, sales of volumes not totally attributable to the interstate pipeline-seller's own production (mixed volume sales) do not qualify for first sale treatment under the attribution rule. Furthermore, such mixed volume sales are not considered first sales under the circumvention rule because they are regulated under the NGA. As a result, the rate for mixed-volume sales by interstate pipelines will continue to be regulated under the NGA.

Under the NGA pipeline production is priced on a cost of service basis or according to area or nationwide rates. However, the Commission is persuaded by several comments received from pipelines in connection with § 270.203 which maintain that it is inequitable for interstate pipelines to be denied the same pricing treatment accorded other producers of natural gas under the NGPA. These comments argue that restricting pipelines to lower prices under the NGA will discourage pipeline production efforts because costs such as severance taxes an royalties are based on the highest market price rather than on the cost of service or some other price and are thus on a parity with independent producers' costs. The comments argue that "parity of costs" requires "parity of price" and that the Commission should continue the parity

of treatment between pipelines and independent producers which the Federal Power Commission (FPC) originated under the NGA.[1]

The Commission agrees that there is a need for parity of treatment between pipelines and other producer where pipelines and producers have been treated similarly in the past with respect to particular natural gas supplies. The FPC established such a policy in Opinion No. 568 "in order to provide a regulatory climate conducive to an aggressive pipeline exploration program." [2] In that opinion, the FPC decided to value gas produced by pipelines or their affiliates from leases acquired after October 7, 1969 and taken into the pipeline's own system, by reference to the just and reasonable area rates established for sales by independent producers, absent a showing of special circumstances by the pipeline. In Opinion No. 699–H, the FPC decided that "natural gas which comes within one of the classes enumerated in the new § 2.56(a)(2) shall be entitled to the rate set forth in that section regardless of the date the lease was acquired by a pipeline or pipeline's affiliate." [3] The FPC continued this policy in Opinion 770–A stating, "We have determined that it is in the public interest for the national rate structure to include pipeline production, and the rates for such production should be determined by date of well commencement, rather than by the date on which the subject lease was acquired." [4] In Opinion No. 749–C [5] the FPC reaffirmed its decision that gas from pre-1973 wells on pre-October 8, 1969 leases would continue to be priced on a cost of service basis. Therefore, production from post-October 7, 1969 leases and production from post 1972 wells on pre-October 8, 1969 leases currently receives the applicable area or nationwide rates accorded independent producers unless a showing of special circumstances is made. Production from pre-1973 wells on pre-October 8, 1969 leases is valued on a cost of service basis.

The Commission is proposing to amend § 2.66 and to add a new § 2.66a to its regulations under the NGA. In general, this new section would permit interstate pipelines and affiliates, which would have been allowed the area or nationwide rates under the NGA, to determine the cost component associated with their own production by reference to NGPA maximum lawful prices for NGA ratemaking purposes if the production does not qualify for first sale treatment under the NGPA. All other pipeline production would continue to receive the same pricing treatment accorded it in the past.

II. Summary of Amendments

The Commission believes that it is appropriate to continue a policy of parity of treatment for pipeline and affiliate production which is priced at the applicable area or nationwide rate. Accordingly, the Commission is proposing to amend § 2.66 of its regulations and to add a new § 2.66a to allow pipelines and their affiliates to value their production, for purposes of rate proceedings under the NGA, at the applicable NGPA Title I prices if such production would otherwise have been valued at the applicable area or nationwide rates.

In order to implement this proposed pricing policy the Commission is also proposing to amend § 154.38(d)(4) to allow pipelines to include in their PGA clauses production which qualifies for

[1] See Opinion No. 568, *Pipeline Production Area Rate Proceeding* (Phase I), 42 F.P.C. 738, *as amended*, 42 F.P.C. 1089 (1972), affirmed, *City of Chicago* v. *F.P.C.*, 147 U.S. App. D.C. 312, 458 F. 2d 731 (D.C. Cir. 1971), *Cert. denied*, 405 U.S. 1074 (1972).

[2] *Pipeline Production Area Rate Proceeding (Phase I)*, *Supra*, at p. 745.

[3] See, Opinion No. 699–H, —— F.P.C. ——, Mimeo p. 47.

[4] See, Opinion No. 770–A, —— F.P.C. ——, Mimeo p. 147.

[5] See, Opinion No. 749–C, —— F.P.C. ——, Mimeo p. 29.

rate treatment by reference to the NGPA prices.

However, the Commission does not propose to extend such parity of treatment to pipeline production which, under the NGA, has not been treated on the same basis as production by independent producers. Much pipeline production, particularly old production, has been priced on a cost of service basis. This treatement provides for recovery of dry hole expenses and assures recovery of the costs of production, including a return, income tax, and depreciation component. This treatment is significantly different from the methods which the Commission has used to establish independent producer rates. These and other differences are emphasized in Opinion No. 568. Given the significant and continuing additional guarantees of cost recovery provided to interstate pipelines by cost of service treatment, we propose that NGPA rates not be extended to pipeline production which has in the past been valued on a cost of service basis. This policy complies with the FPC's decision, following the issuance of Opinion No. 568, that cost of service treatment rather than area and nationwide producer rates should continue to be applied generally to old pipeline production.[6]

Accordingly, we propose that under § 2.66a production from pre-1972 wells on leases acquired on or before October 7, 1969 continue to be priced on a cost of service basis. Production from post-October 7, 1969 properties and post-1972 wells, previously priced with reference to the area and nationwide rates, would be priced with reference to maximum lawful prices in Title I of the NGPA unless the production had been accorded special treatment by the Commission under Opinion Nos. 568, 699-H, and 770-A following a showing of special circumstances by the pipeline that the otherwise applicable area or nationwide rate was insufficient. Production which received cost of service treatment based on a showing of special circumstances would continue to receive cost of service treatment. Where the Commission has permitted higher rates after a showing of special circumstances, all or portions of the costs related to the acquisition of leases, drilling of exploratory and developmental wells and other necessary attendant operations, such as the holding of undeveloped properties for future use, have been paid for by the pipeline's customers. Therefore, NGPA Title I rates should not be permitted for such production.

Under proposed § 2.66a a pipeline would be prohibited from seeking relief from the otherwise applicable rate via the special circumstances route, for production from leases acquired subsequent to the effective date of this proposed amendment and other production to which § 2.66a applies.[7] However, a pipeline would be permitted to make use of the special relief provisions in the Commission's regulations under the NGPA in order to seek relief from the effects of § 2.66a for production which is priced on the same basis as independent producers.

It is appropriate that this Notice of Proposed Rulemaking delineate the interrelationship between our treatment of cost of service pipeline production and our treatment of affiliate sales under § 270.203(c). Under § 270.203(c) a sale by an affiliate of a pipeline or distributor is a first sale if the affiliate company is not itself a pipeline or distributor and the Commission does not specifically determine otherwise.

The Commission recognizes that under § 270.203 a pipeline could attempt

[6] See, Opinion No. 749-C, —— F.P.C. ——, mimeo p. 29.

[7] We note that Columbia Gas Transmission Corporation (Docket No. RP75-106) has a proposal before the Commission under § 2.66(a)(4) which has been the subject of litigated proceedings; the proposal will be disposed of by the Commission on the basis of the record. Moreover, we note that Michigan-Wisconsin Pipeline Company received cost of service treatment under § 2.66(a)(4) for the period, November 1, 1973-October 31, 1977, and that the Commission in approving settlements covering rates for subsequent periods has expressly disavowed any policy determination regarding the pricing approach incorporated in the settlements. This matter will be the subject of a separate order.

to obtain first sale treatment for its cost of service pipeline production by transferring that production to an affiliate and then entering into a contract with the affiliate to purchase the transferred cost of service production. This would have the effect of qualifying the sale of that production as a first sale under § 270.203(c). However, the Commission cautions that any such transfer of an interstate pipeline's production would require that the interstate pipeline file an abandonment application. Opinion No. 626, *Panhandle Eastern Pipe Line Company, et al.*, Docket Nos. CP71-237, *et al.*, 48 F.P.C. 518 (1972). Moreover, since the gas so transferred is "committed or dedicated to interstate commerce" within the meaning of section 2(18) of the NGPA, the affiliate would be required to file a certificate application in order to make the sale to the interstate pipeline.

The Commission advises that, should it adopt the proposed rule, it would scrutinize closely abandonment and certificate applications involving pipeline production. Although the Commission recognizes that valid reasons may be advanced in support of abandonment and certificate applications involving pipeline production, it would attempt to assure itself in *all* cases that the transfer of pipeline production to an affiliate would not result in pricing pipeline production differently than it would have been priced had the pipeline retained ownership of such production. [8]

In order to implement this proposed policy in those cases where favorable action on abandonment and certificate applications would otherwise be appropriate, the Commission will consider these applications and exercise its authority so as to assure continued cost of service treatment for pre 1973 wells on pre-1969 leases except in extraordinary circumstances. The Commission retains authority over cost of service gas under the express provisions of section 601(a)(1)(B) of the NGPA. Section 601(a)(1)(B) of the NGPA provides that the Commission's NGA jurisdiction over this gas is unaffected by passage of the NGPA, unless a final determination is received that the natural gas from these old wells is high-cost natural gas (as defined in section 107(c) (1), (2), (3), or (4)), or new natural gas (as defined in section 102(c)). [9] The treatment proposed for certificate and abandonment applications would provide consistent and symmetrical pricing policies for pipeline production, irrespective of whether that production were sold by the pipeline as part of its system supply, or were sold separately by an affiliate. This treatment would also assure that the pipeline's decision to produce its own gas or to transfer that production to an affiliate would be made on the basis of factors other than price.

III. Public Procedure

The Commission intends to issue § 2.66a as a substantive rule, rather than as a statement of policy, after receiving and evaluating comments on this proposed rulemaking. Interested persons are invited to submit written comments, data, views or arguments with respect to the provisions of § 2.66a. All submissions should reference Docket No. RM80-6. An original and 14 copies should be filed with the Secretary of the Commission. All comments received by January 14, 1980 will be considered by the Commission prior to issuing final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426.

A public hearing on this proposed rulemaking will be held in Washington,

[8] The extent to which the Commission can obtain these assurances for new pipeline production which has been priced on a cost-of-service basis, based upon a showing of "special circumstances" under section 2.66 of our regulations, is not clear.

[9] By definition, natural gas from these old wells cannot qualify for the section 103 price.

D.C. on Monday, January 7, 1980. The hearing will be held at the Federal Energy Regulatory Commission, Hearing Room A, 825 North Capitol Street, NE., Washington, D.C., and will begin at 10:00 a.m., local time.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should be made no later than December 28, 1979. Requests should reference Docket No. RM80-6 and should indicate the name of the party who will be making the presentation, a phone number at which that party may be contacted, and the amount of time requested for the presentation. Persons participating in the public hearing should, if possible, bring 25 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Office of Public Information prior to the hearing and will be available in the hearing room on the morning of the hearing.

The hearing will not be of a judicial or evidentiary nature, and there will be no cross-examination of persons presenting statements. The presentations will be made before a panel whose members will be designated by the Chairman. Members participating on the panel may ask questions. If time permits, they may also ask such additional relevant questions as are submitted to them by participants. Other procedural rules relating to the presentations will be announced at the time the proceedings commence. A transcript of the hearing will be available in the public file for this proceeding in the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*; Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; E.O. 12009, 42 FR 46257)

In consideration of the foregoing, the Commission is proposing to amend Part 2 of Subchapter A, Part 154 of Subchapter E, and Part 270 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 2—GENERAL POLICY AND INTERPRETATIONS

§ 2.66 [Amended]

1. Part 2 is amended in the table of contents and in the text of the regulations by inserting in the title of § 2.66 the phrase "which is not subject to § 2.66a." after the word "affiliates" and is further revised by adding at the end of the text of § 2.66 the following new paragraph:

• • • • •

(e) *Inapplicability to certain gas produced on or after December 1, 1978.* This section does not apply to natural gas to which § 2.66a is applicable.

• • • • •

2. Part 2 is further amended in the table of contents and in the text of the regulations by adding after § 2.66 the following new section:

§ 2.66a Pricing of certain gas produced on or after December 1, 1978, by pipelines and pipeline affiliates.

(a) *Applicability.* This section applies to natural gas which is produced by an interstate pipeline or an affiliate of such pipeline and which is delivered to such pipeline, other than in a first sale, if:

(1) Such gas is produced on or after November 15, 1979; or

(2) Such gas is produced on or after December 1, 1978, and before November 15, 1979, and is specifically made subject by Commission order to the outcome of the proceeding in which this section has been promulgated.

(b) *Policy Statement.* As a matter of policy in any pipeline rate proceeding (including a PGA proceeding):

(1) *NGPA rate treatment*— (i) *General rule.* Subject to paragraph (b)(1) (ii) and (iii) of this section, natural gas produced by an interstate pipeline (or affiliate thereof) to which this section applies shall be priced for ratemaking purposes at the maximum lawful price which

would have been applicable under Subchapter H had the gas been delivered to the pipeline in a first sale, if the production is from a lease owned by such pipeline or affiliate and if:

(A) The lease was acquired after October 7, 1969; or

(B) The natural gas is:

(*1*) Produced form a well commenced on or after January 1, 1973, or

(*2*) Produced through a well commenced prior to such date as a result of a completion operation commenced on or after such date into a different, formerly nonproductive reservoir; or

(C) The Commission, prior to December 1, 1978, had granted area or nationwide rate treatment for such gas in lieu of otherwise applicable cost of service treatment.

(ii) *Conditions.* (A) Natural gas to which this subparagraph applies may be priced at a rate prescribed under Subparts B, C, D, G, H, or J of Part 271 and under Subpart K, only if the pipeline (or affiliate thereof) complies with the requirements of section 601(b)(1)(E) of the NGPA, § 154.94 and Subchapter H which would have been applicable had the natural gas been delivered pursuant to a first sale.

(B) Treatment as provided under paragraph (b)(1)(i)(C) of this section shall continue to be accorded only during the period provided for such area or nationawide rate treatment in applicable Commission orders and shall be subject to the conditions specified in those orders.

(iii) *Exceptions.* This subparagraph does not apply to natural gas produced from leases acquired before November 15, 1979, which have ever been granted cost of service treatment pursuant to § 2.66(a)(4) (relating to special circumstances).

(2) *Cost of service rate treatment.* Natural gas to which this section applies, but which is not covered by paragraph (b)(1) of this section, shall be priced for ratemaking purposes on a cost of service basis.

(c) *Definitions.* For purposes of this section:

(1) *NGPA definitions.* The terms "interstate pipeline", "affiliate", and "first sale" have the same meaning as they have for purposes of Subchapter H.

(2) *Lease.* The term "lease" includes any fee interest in producing property or any working interest in production.

PART 154—RATE SCHEDULES AND TARIFFS

§ 154.38 [Amended]

3. Part 154 is amended by deleting the first sentence in footnote 1 to § 154.38(d)(4) and substituting the following sentence in lieu thereof:

[1] For the purposes of this paragraph, purchased gas costs represent the cost of well head purchases, field line purchases, plant outlet purchases, transmission line purchases, and pipeline or affiliate production that qualifies for an is allowed an area or nationwide rate under § 2.66 of this chapter or a maximum lawful price specified in Title I of the NGPA under § 2.66a.* * *

PART 270—RULES GENERALLY APPLICABLE TO REGULATED SALES OF NATURAL GAS

4. Part 270 is amended in § 270.203 by adding a new paragraph (f) to read as follows:

§ 270.203 Pipeline distributor and affiliate production.

* * * * *

(f) *Cross reference.* In treatment of interstate pipeline and affiliate production delivered to a pipeline other than in a first sale, see Part 266 and Part 266a of this chapter.

¶ 32,045 Price Squeeze—Procedural Rules

44 F. R. 67154 (November 23, 1979).

18 CFR Part 35

[Docket No. RM79-79]

Price Squeeze—Procedural Rules

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its Regulations under the Federal Power Act (18 CFR Part 35) by adding a new § 35.30 which would establish the procedural rules governing Commission proceedings involving an issue of price squeeze in the electric industry. On this date and in a companion rulemaking (Docket No. RM79-80), the Commission is proposing to add a new § 35.32 to Part 35, which would establish the substantive rules relating to Commission consideration of a price squeeze issue. New §§ 35.30 and 35.32 together would supersede present § 2.17 of the Commission's regulations on General Policy and Interpretations (18 CFR Part 2).

DATE: Written comments by: December 24, 1979. Public hearing to be announced.

ADDRESS: Written comments should be filed with the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM79-79.

HEARING LOCATION: To be announced.

FOR FURTHER INFORMATION CONTACT:

Angela Lancaster, Office of the Chairman, Federal Energy Regulatory Commission, Room 9000, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8333

or

Bonnie Cord, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8104-A, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8170.

SUPPLEMENTARY INFORMATION:
Issued: November 19, 1979.

I. Background

The Federal Energy Regulatory Commission (Commission) is proposing to amend its Regulations under the Federal Power Act (18 CFR Part 35) by adding a new § 35.30 which would establish the procedural rules governing Commission proceedings involving an issue of price squeeze in the electric industry. On this date and in a companion rulemaking (Docket No. RM79-80), the Commission is also proposing to add a new § 35.32 to Part 35, which would establish the substantive rules relating to Commission consideration of a price squeeze issue. New §§ 35.30 and 35.32 together would supersede present § 2.17 of the Commission's regulations concerning General Policy and Interpretations (18 CFR Part 2).

Price squeeze is the term used to describe price discrimination, with an anticompetitive effect, against an electric utility's wholesale customer. Specifically, price squeeze exists if a utility's price for wholesale service is higher in relation to wholesale costs than is the utility's price for retail service in relation to retail costs, resulting in actual or potential impairment of the wholesale customer's ability to compete with the utility for retail service.

The Federal Power Commission (predecessor of the Federal Energy Regulatory Commission) addded § 2.17 to its regulations on March 21, 1977, in Order No. 563. That section was added to comply with the Supreme Court's decision in *F.P.C. v. Conway Corp.*, 426 U.S. 271 (1976), *aff'g* 510 F.2d 1264 (D.C. Cir. 1975), which required the Commission to consider price squeeze as part of its determination as to whether a utility's wholesale rate is just and reasonable. Section 2.17 established the substantive and procedural

guidelines to be followed by parties in trying price squeeze cases before the Commission.

When § 2.17 was promulgated, the Federal Power Commission recognized that it did not have sufficient experience with price squeeze issues to promulgate a rule concerning price squeeze and, therefore, issued § 2.17 as a Statement of Policy. Since that time, the Commission staff (staff) and other participants to proceedings involving price squeeze issue have developed practical experience working under the procedures and requirements specified in § 2.17. The Commission has issued several decisions which resolve many of the substantive and procedural questions involved in the consideration of a price squeeze issue. Further, the Commission has reviewed most of the questions in a generic manner at public meetings held on June 28 and 29, 1979. The experience gained since promulgation of § 2.17, the issued decisions, and the Commission's conclusions at the public meetings are reflected in this proposed rulemaking and in the companion proposed rulemaking which would establish new § 35.32.

II. Summary of the Proposed Regulations

Paragraph (a) of new § 35.30 provides that the procedures in this section are applicable to proceedings involving price squeeze as defined in § 35.32(b)(1).

Paragraph (b) of § 35.30 provides that the definitions set forth in § 35.32 also apply to § 35.30. That paragraph also defines the term "top sheets."

Paragraph (c) of § 35.30 establishes the proceedings in which, and the procedures by which, price squeeze may become an issue in a Commission proceeding. Subparagraph (1) lists the types of proceedings in which the issue of price squeeze may be raised. That subparagraph provides that price squeeze may be alleged against an electric utility in any proceeding arising from the filing, by the utility, of a request for increased rates under § 35.13 or of an initial rate under § 35.12 or in any proceeding involving that utility's rates conducted pursuant to section 206 of the Federal Power Act (16 U.S.C. 824e (a) and (b)). Subparagraph (2) of paragraph (c) establishes the procedures by which price squeeze may become an issue in proceedings specified in subparagraph (1). The procedures set forth in subparagraph (2)(i) through (iii), relating to intervention and complaints are essentially identical to, and merely clarify, the procedures set forth in § 2.17. The provisions of subparagraph (2)(iv), articulating procedures pertaining to the staff, incorporate the Commission's decision in *Connecticut Light and Power Company*, Docket No. ER78-517 (August 20, 1979). In that decision the Commission recognized that the staff is not required to file a petition to intervene and that the staff is unlikely at the initial intervention stage to have the information necessary to determine whether the price squeeze issue has merit. The Commission held that the staff would be permitted to submit a motion to expand the scope of the proceeding if the price squeeze issue has not been raised by an intervenor or complainant, or if an intervenor or complainant has failed to establish a *prima facie* case. Specific authority was given to the presiding judge to rule on such a motion, after the granting of which the staff would be held to the same procedural and substantive requirements as any other participant in the proceeding. In the event that an intervenor or complainant had made a *prima facie* case, the staff would be permitted to participate as a matter of course.

Paragraph (d) provides that if no intervenor or complainant has raised the issue of price squeeze in accordance with paragraph (c), the staff may file with the presiding judge a "Motion to expand the scope of the proceding" at any time prior to the issuance of top sheets. In that situation, price squeeze will be an issue in the proceeding only if the judge grants the staff's motion.

Paragraph (e) of §35.30, which describes the structure of a proceeding involving a price squeeze issue,

incorporates the Commission's decisions in several cases. In an order issued in *Arkansas Power and Light Company*, Docket No. ER79-339, (August 6, 1979) a section 205 proceeding, the Commission stated that it preferred to consider the price squeeze issue in a separate phase of the proceeding (phasing) and held that, in all newly docketed cases in which price squeeze was alleged, all other issues in the proceeding would be considered and decided prior to consideration of the price squeeze issue. However, the Commission granted discretion to the presiding judge, on his or her own motion or the motion of the staff or any party, to determine not to phase the price squeeze issue.

The Commission held further that, if phasing were ordered, the first phase or phases would address and resolve the cost of service (including capitalization and rate of return) issues, after which a preliminary Commission decision would be issued and any refunds to the level of the rate specified in the preliminary decision would be ordered by the Commission. The issue of price squeeze would then be considered in a new phase of the party alleging price squeeze determined that the preliminary just and reasonable wholesale rate still presented a price squeeze and determined to pursue its price squeeze allegations. The Commission advocated such phasing because resolution of the cost of service issues often eliminates, or at least substantially diminishes, any unjustified disparity between the wholesale and retail rates so that the price squeeze issue no longer exists. In addition, as the Commission noted in *Southern California Edison Company*, Opinion No. 62 at 29 (August 22, 1979), this procedure allows the wholesale customers to obtain refunds of all amounts collected in excess of the preliminary just and reasonable rate at an earlier date.

In an order issued in *Public Service Company of New Mexico*, Docket Nos. ER79-478 and ER79-479 (August 28, 1979), the Commission adopted a different approach for filings involving contracts under which rates may be increased only after issuance of a final Commission opinion. In that case, the Commission did not phase the price squeeze issue on the section 206 filing, since under section 206 no rate relief can be afforded until the end of the entire proceeding. Although the Commission did not order phasing in that proceeding, it gave the presiding judge authority to order phasing in his or her discretion provided that the utility did not object. Further, even though that docket also concerned a section 205 filing, the Commission declined to order phasing of the price squeeze issue pertaining to that filing, again leaving discretion to order phasing with the presiding judge.

Paragraph (e) of §35.30 incorporates the decisions in these cases with respect to phasing the price squeeze issue. Subparagraph (l)(i) specifies the proceedings which will be phased automatically. Clause (ii) of subparagraph (l) provides that the presiding judge has discretion to order that these proceedings not be phased if he or she determines that circumstances exist which warrant not phasing the price squeeze issue. As discussed in the Notice proposing the establishment of §35.32 (Docket No. RM79-80), issued simultaneously with this rulemaking, the Commission has determined that, in light of the Commission's limited remedial powers, the preliminary just and reasonable wholesale rate is the appropriate rate to be compared with the relevant retail rate for price squeeze purposes. Consistent with this determination, the Commission emphasizes its strong preference for phasing of the price squeeze issue. Although the Commission cannot at this time conceive of circumstances which would warrant unphasing of proceedings specified in subparagraph (l)(i), discretion has been given to the presiding judge to determine in a particular case that such circumstances exist.

Subparagraph (2) of paragraph (e) specifies those proceedings in which the price squeeze issue will be phased if the judge so orders, unless the utility objects.

Paragraph (f) establishes procedures pertaining to the presiding judge's decision on phasing and provides opportunity for the staff or any party to argue before the presiding judge on phasing.

Paragraph (g) sets forth the procedures governing consideration of the price squeeze issue if phasing has been ordered. Subparagraph (1) provides that, if so ordered by the Commission, the wholesale rate, established by the Commission prior to commencement of the price squeeze phase of the proceeding (the "preliminary just and reasonable wholesale rate"), will be charged during the price squeeze phase and that the wholesale customer may collect any refunds ordered by the Commission should the preliminary just and reasonable wholesale rate be less than the rate previously charged.[1]

Subparagraph (2) of paragraph (g) requires that the price squeeze allegations be renewed by parties after completion of the cost of service phases. Except as provided in paragraph (g)(3), if the price squeeze allegations are not renewed, the preliminary just and reasonable wholesale rate is deemed to be the final just and reasonable wholesale rate.

Subparagraph (3) of paragraph (g) provides that, if no renewed allegations have been filed under subparagraph (2), and if the staff wishes to litigate the price squeeze issue, the staff shall submit to the Commission a "Motion to continue consideration of the price squeeze issue." If the staff's motion is denied by the Commission, price squeeze will not be considered in the proceedings and the preliminary just and reasonable wholesale rate shall be deemed the final just and reasonable wholesale rate.

Subparagraphs (4) through (10) of paragraph (g) specify the time limits for further submissions on the price squeeze issue.

Paragraph (h) sets forth the procedures governing consideration of the price squeeze issue if phasing has not been ordered. These procedures are essentially the same as those established in paragraph (g), with the exception that different procedures are applicable to the staff in accordance with the Commission's decision in *Connecticut Light and Power*, discussed above. Subparagraph (10) provides that the staff may request by motion permission to litigate the price squeeze issue if the parties have failed to make the *prima facie* case. Subparagraphs (11) through (13) establish the applicable procedures, if the presiding judge grants the staff's motion. Subparagraph (14) directs the presiding judge to establish procedural dates for further consideration of the price squeeze issue if the elements of a *prima facie* case have been satisfied.

III. Public Comments and Public Hearing

The Commission invites interested persons to submit written data, views and other information with respect to the matters contained in this notice. All comments should be verified, should reference Docket No. RM79–79, and should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. An original and 14 conformed copies should be filed. All such submissions filed by December 24, 1979, will be considered by the Commission prior to issuance of a final rule.

All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

The Commission intends to conduct a public hearing on the matters contained in this notice and in the companion

[1] After the Commission rules on an application for rehearing of the Commission's preliminary decision, the Commission believes that any party that applied for rehearing may seek court review of the Commission's preliminary just and reasonable rate level determination in accordance with section 313 of the Federal Power Act.

notice (Docket No. RM79-80). The members of the panel at that hearing will be designated by the Chairman of the Commission. The date, location and procedures will be announced in the near future.

(Federal Power Act, 16 U.S.C. §§ 791-828c; Department of Energy Organization Act, 42 U.S.C. §§ 7101-7352, E.O. 12009, 42 Fed. Reg. 46267)

In consideration of the foregoing, the Commission is proposing to amend Part 35, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 35—FILING OF RATE SCHEDULES

1. Part 35 is amended in the Table of Contents by adding in the appropriate numerical order a new section and heading to read as follows:

§ 35.30 Price squeeze—procedural rules.

2. Part 35 is further amended in the Statement of Authority by adding the following phrase to the end thereof:

42 U.S.C. 7101-7352, E.O. 12009, 42 F.R. 46467.

3. Part 35 is further amended by adding § 35.30 to read as follows:

§ 35.30 Price squeeze—procedural rules.

(a) *Applicability.* This section sets forth the procedures applicable to proceedings in which the issue of price squeeze, as defined in § 35.32 of this chapter, is alleged.

(b) *Definitions.* The definitions set forth in § 35.32 of this chapter apply to this section. For purposes of this section the term "top sheets" means the cost of service analysis prepared by the staff for settlement purposes only and served upon all parties to the proceeding in advance of the first scheduled settlement conference.

(c) *Price squeeze as an issue in a Commission proceeding.* (1) Price squeeze may be an issue in the following proceedings:

(i) Any proceeding arising from a filing for a rate increase made by an electric utility under § 35.13;

(ii) Any proceeding arising from a filing of an initial rate made by an electric utility under § 35.12; and

(iii) Any proceeding concerning the electric utility's rates which is conducted pursuant to section 206 of the Federal Power Act.

(2) Price squeeze may be considered as an issue in those proceedings specified in paragraph (c)(1) of this section only if:

(i) a person files with the Commission a petition to intervene, in accordance with § 1.8 of this chapter, alleging a price squeeze;

(ii) a State Commission files with the Commission a notice of intervention, in accordance with § 1.8, alleging a price squeeze;

(iii) a person files a complaint with the Commission pursuant to section 206 of the Federal Power Act, in accordance with § 1.6 of this chapter, alleging a price squeeze; or

(iv) the staff files with the presiding judge, as specified in paragraph (d) of this section a motion alleging a price squeeze.

(3) When price squeeze becomes an issue in a Commission proceeding, the Secretary shall add to the service list, maintained under § 1.17(c) of this chapter, the State Commission, agency or body that is responsible for regulation of retail rates for each State in which the utility provides electric service.

(d) *Raising of price squeeze issue by the staff.* (1) If no intervenor or complainant has alleged price squeeze in accordance with paragraph (c)(2) (i) through (iii) of this section, the staff may file with the presiding judge a "Motion to expand the scope of the proceeding" at any time prior to the issuance of top sheets.

(2) If the presiding judge grants the staff's motion under paragraph (d)(1) of this section, price squeeze shall be an issue in the proceedings. If the judge denies the staff's motion, price squeeze shall not be an issue in the proceeding.

(e) *Phasing of proceedings involving the price squeeze issue.* (1) This subparagraph applies to proceedings arising solely under section 205 in which the proposed wholesale rates may become effective subject to refund or a proceeding involving certain complaints under section 206 of the Federal Power Act.

(i) A proceeding specified in paragraph (e)(1)(i) (A) or (B) of this section shall be conducted in separate phases if price squeeze is an issue, unless the presiding judge orders otherwise under paragraph (e)(ii) of this section. The initial phase or phases shall resolve all issues regarding cost of service and shall result in a determination by the Commission of a preliminary just and reasonable wholesale rate. The price squeeze issue shall be considered in a subsequent phase in accordance with the provisions of paragraph (g) of this section. This subparagraph applies to the following proceedings:

(A) proceedings which arise solely from a filing by an electric utility of a proposed increased rate under § 35.13 which may become effective subject to refund or an initial rate under § 35.12; or

(B) proceedings which arise from the filing of a complaint under § 1.6 of this chapter and pursuant to section 206 of the Federal Power Act, which complaint alleges that an electric utility's rate is excessive.

(ii) The presiding judge may determine on his or her own motion, or upon motion of the staff or any party, that circumstances exist which warrant that all or part (*e.g.*, discovery) of the price squeeze issue not be considered in a separate phase.

(2) If price squeeze is an issue in a proceeding conducted entirely under section 206 of the Federal Power Act, other than a proceeding described in paragraph (e)(1)(i) (A) or (B) of this section, the presiding judge may determine that the price squeeze issue be considered in a separate phase of the proceeding, unless the electric utility whose rates are the subject of the proceeding objects to the consideration of the price squeeze issue in a separate phase.

(3) Any determination on phasing the proceeding which is made by a presiding judge under this paragraph shall be made in accordance with the procedures specified in paragraph (f) of this section.

(f) *Procedures for determination on phasing.* (1) Within fifteen days after issuance of the order setting the matter for hearing, or within fifteen days after the granting of staff's "Motion to expand the scope of the proceeding" under paragraph (d) of this section, the staff or any party may file with the presiding judge a motion requesting that the price squeeze issue not be considered in a separate phase of a proceeding specified in paragraph (e)(1) of this section, or that the price squeeze issue be considered in a separate phase of a proceeding specified in paragraph (e)(2) of this section.

(2) Within five days after the date by which all motions made under paragraph (f)(1) of this section are to be filed, the staff or any party may file with the presiding judge a reply to such motions.

(3) Within ten days after the date by which replies made under paragraph (f)(2) of this section are to be filed, the presiding judge shall issue a decision on whether to consider the price squeeze issue in a separate phase.

(4) If the judge decides to consider the price squeeze issue in a separate phase, that phase shall be conducted in accordance with paragraph (g) of this section. If the judge decides not to consider the price squeeze issue in a separate phase, the proceeding shall be conducted in accordance with paragraph (h) of this section.

(g) *Procedures if there is separate phasing of the price squeeze issue.* The following procedures apply to proceedings in which the price squeeze issue is considered in a separate phase.

(1) If so ordered by the Commission, the utility shall charge the preliminary just and reasonable wholesale rate or rates during the price squeeze phase and shall refund any amounts collected during all prior phases of the proceeding

which are in excess of the preliminary just and reasonable wholesale rate or rates.

(2) Except as provided in paragraph (g)(3) of this section, unless the alleging party refiles its price squeeze allegation after the final decision establishing the preliminary just and reasonable wholesale rates has been issued but no later than thirty days after the Commission accepts the utility's compliance filing, the price squeeze issue shall not be considered in the proceeding and the preliminary just and reasonable wholesale rate shall be deemed to be the just and reasonable wholesale rate.

(3) If no price squeeze allegations have been refiled by intervenors or complainants within the time period specified in paragraph (g)(2) of this section or if the price squeeze issue was not raised by intervenors or complainants in accordance with paragraph (c)(2)(i) through (iii) of this section, and if the staff wishes to litigate the price squeeze issue, the staff shall submit to the Commission a "Motion to continue consideration of the price squeeze issue, no later than seven days after the end of the time period specified in paragraph (g)(2) of this section. If the staff's motion is denied by the Commission, the price squeeze issue shall not be considered in the proceeding and the preliminary just and reasonable wholesale rate shall be deemed to be the just and reasonable wholesale rate.

(4) Within fifteen days after the date by which renewed allegations must be filed under paragraph (g)(2) of this section, or within fifteen days after the date on which the Commission grants the staff's motion under paragraph (g)(3) of this section, intervenors, complainants or the staff shall file with the presiding judge any requests for data required to present their case.

(5) Within fifteen days after the date by which data requests must be filed under paragraph (g)(4) of this section, the presiding judge shall convene a prehearing conference for the purpose of hearing argument on such data requests. At the conference the judge shall identify the specific data requests to which the utility will be required to respond.

(6) Within thirty days after the date of the prehearing conference specified in paragraph (g)(5) of this section, the utility shall respond to the data requests identified by the judge under paragraph (g)(5) of this section.

(7) Within thirty days after the date on which the utility makes a response under paragraph (g)(6) of this section intervenors, complainants, and the staff shall file their *prima facie* cases, as described in § 35.32(c).

(8) Within fifteen days after the date by which the *prima facie* case (or cases) is to be filed under paragraph (g)(7) of this section, the staff or any party may file a pleading alleging that such *prima facie* case does or does not fulfill the requirements of § 35.32(c).

(9) Within twenty days after the date by which pleadings are to be filed under paragraph (g)(8) of this section, the presiding judge shall determine whether the case filed under paragraph (g)(7) of this section satisfies the requirement of a *prima facie* case specified in § 35.32(c). If the judge determines that the requirements for a *prima facie* case have been satisfied, that determination shall not be reviewable by the Commission.

(10) If the presiding judge decides that the requirements for a *prima facie* case have been satisfied, the presiding judge shall set procedural dates for the following:

(i) submission by the utility of evidence (including evidence relating to the *prima facie* case) to justify the preliminary just and reasonable wholesale rate;

(ii) submission of additional evidence which the judge in her or his discretion deems appropriate; and

(iii) commencement of the hearing.

(h) *Procedures if there is no separate phasing of the price squeeze issue.* The following procedures apply to proceedings in which the price squeeze issue is not considered in a separate phase.

(1) Intervenors or complainants shall file with the presiding judge any requests for data required to present their cases:

(i) if no motions concerning the phasing of the proceeding have been filed under paragraph (f)(1) of this section, within thirty days after issuance of the order setting the matter for hearing or within thirty days after the granting of the staff's "Motion to expand the scope of the proceedings" under paragraph (d) of this section; or

(ii) if a motion concerning the phasing of the proceeding has been made under paragraph (f)(1) of this section, within fifteen days after the judge's determination under paragraph (e) of this section, that the proceeding will not be phased.

(2) Within ten days after the date by which data requests must be filed by intervenors and complainants under paragraph (h)(1) of this section, the staff file with the presiding judge any requests for data required to present its case.

(3) Within fifteen days after the date by which data requests must be filed under paragraph (h)(2) of this section, the presiding judge shall convene a prehearing conference for the purpose of hearing argument on data requests filed under paragraphs (h) (1) and (2) of this section. At the conference, the judge shall identify the specific data requests to which the utility will be required to respond.

(4) Within thirty days after the data of the prehearing conference specified in paragraph (h)(3) of this section, the utility shall respond to the data requests of intervenors and complainants filed under paragraph (h)(1) of this section and identified by the judge under paragraph (g)(3) of this section.

(5) Within twenty days after the date on which the utility is required to make a response under paragraph (h)(4) of this section, the utility shall respond to the data requests of the staff filed under paragraph (h)(2) of this section, and identified by the judge under paragraph (h)(3) of this section.

(6) Within thirty days after the date on which the utility makes a response under paragraph (h)(4) of this section, intervenors and complainants shall file their *prima facie* cases, as described in § 35.32(c).

(7) Within fifteen days after the date by which the *prima facie* case (or cases) is to be filed under paragraph (h)(6) of this section, the staff or any party may file a pleading alleging that such *prima facie* case does or does not fulfill the requirements of § 35.32(c).

(8) Within twenty days after the date by which pleadings are to be filed under paragraph (h)(7) of this section, the presiding judge shall determine whether the case filed under paragraph (h)(6) of this section satisfies the requirements of a *prima facie* case specified in § 35.32(c). If the judge determines that the requirements for a *prima facie* case have been satisfied, that determination shall not be reviewable by the Commission and the staff shall not be required to file a *prima facie* case.

(9) If the judge determines under paragraph (h)(8) of this section, that the requirements of a *prima facie* case have not been satisfied, the staff may file with the judge a "Motion to continue consideration of the price squeeze issue" within fifteen days after the date of the judge's determination under paragraph (h)(8) of this section. If the staff has filed such a motion within the specified time, the presiding judge shall determine whether to grant or deny the motion. If the presiding judge denies the staff's motion, or if the staff did not file such motion within the specified time, the price squeeze issue shall not be considered further in the proceeding.

(10) Within fifteen days after the presiding judge grants the staff's motion under paragraph (h)(9) of this section, the staff shall file its *prima facie* case, as described in § 35.32(c).

(11) Within fifteen days after the date by which the staff's *prima facie* case is to be filed under paragraph (h)(10) of this section, any party or the staff may file a pleading alleging that such *prima facie* case does or does not fulfill the requirements of § 35.32(c).

(12) Within twenty days after the date by which pleadings are to be filed under paragraph (h)(11) of this section, the presiding judge shall determine whether the staff's *prima facie* case satisfies the requirements of a *prima facie* case specified in § 35.32(c). If the judge determines that the requirements for a *prima facie* case have been satisfied, that determination shall not be reviewable by the Commission. If the presiding judge determines that the requirements of the *prima facie* case have not been satisfied, the price squeeze issue shall not be considered further in the proceeding.

(13) If the presiding judge determines under paragraph (h)(8) or paragraph (h)(12) of this section that the elements of a *prima facie* case have been satisfied, the presiding judge shall set procedural dates for the following:

(i) submission by the utility of evidence (including evidence relating to the *prima facie* case) to justify the proposed wholesale rate;

(ii) submission of additional evidence which the judge in his or her discretion deems appropriate; and

(iii) commencement of the hearing.

(i) *Change of procedural dates under this section.* The presiding judge may, in his or her discretion, and for good cause shown, change any procedural dates specified in this section.

¶ 32,046 Price Squeeze—Substantive Rules

44 F. R. 67158 (November 23, 1979).

18 CFR Part 35

[Docket No. RM79-80]

Price Squeeze—Substantive Rules

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its Regulations under the Federal Power Act (18 CFR Part 35) by adding a new § 35.32 which would establish the substantive rules governing Commission proceedings involving an issue of price squeeze in the electric industry. On this date and in a companion rulemaking (Docket No. RM79-79), the Commission is proposing to add a new § 35.30 to Part 35, which would establish the procedural rules relating to Commission consideration of a price squeeze issue. New §§ 35.30 and 35.32 together would supersede present § 2.17 of the Commission's regulations on General Policy and Interpretations (18 CFR Part 2).

DATE: Written comments by: December 24, 1979. Public hearing to be announced.

ADDRESS: Written comments should be filed with the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM79-80.

HEARING LOCATION: To be announced.

FOR FURTHER INFORMATION CONTACT:
Angela Lancaster, Office of the Chairman, Federal Energy Regulatory Commission, Room 9000, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8333, or
Bonnie Cord, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8104-A, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8170.

SUPPLEMENTARY INFORMATION:

Issued: November 19, 1979.

I. Background

The Federal Energy Regulatory Commission (Commission) is proposing to amend its Regulations under the Federal Power Act (18 CFR Part 35) by adding a new § 35.32 which would establish the substantive rules governing Commission proceedings involving an issue of price squeeze in the electric industry. On this date and in a companion rulemaking (Docket No. RM79-79), the Commission is proposing to add a new § 35.30 to Part 35, which would establish the procedural rules relating to Commission consideration of a price squeeze issue. New §§ 35.30 and 35.32 together would supersede present § 2.17 of the Commission's regulations on General Policy and Interpretations (18 CFR Part 2).

Price squeeze is the term used to describe price discrimination, with an anticompetitive effect, against an electric utility's wholesale customer. Specifically, price squeeze exists if a utility's price for wholesale service is higher in relation to wholesale costs than is the utility's price for retail service in relation to retail costs, resulting in actual or potential impairment of the wholesale customer's ability to compete with the utility for that retail service.

The Federal Power Commission (predecessor to the Federal Energy Regulatory Commission) added § 2.17 to its regulations on March 21, 1977, in Order No. 563. That section was added to comply with the Supreme Court's decision in *F.P.C.* v. *Conway Corp.*, 426 U.S. 271 (1976), *aff'g* 510 F. 2d 1264 (D.C. Cir. 1975), which required the Commission to consider price squeeze as part of its determination as to whether a utility's wholesale rate is just and reasonable. Section 2.17 established the substantive and procedural guidelines to be followed by parties in

trying price squeeze cases before the Commission.

When § 2.17 was promulgated, the Federal Power Commission recognized that it did not have sufficient experience with price squeeze issues to promulgate a rule concerning price squeeze and therefore, issued § 2.17 as a Statement of Policy. Since that time, the Commission staff (staff) and other participants to proceedings involving a price squeeze issue have developed practical experience working under the procedures and requirements specified in § 2.17. The Commission has issued several decisions which resolve many of the substantive and procedural questions involved in the consideration of a price squeeze issue. Further, the Commission has reviewed most of the questions in a generic manner at public meetings on June 28 and 29, 1979. The experience gained since promulgation of § 2.17, the issued decisions, and the Commission's conclusions at the public meetings are reflected in this proposed rulemaking and the companion proposed rulemaking which would establish new § 35.30.

II. Analysis of the Issues

In designing § 2.17, the Federal Power Commission was concerned that there would be a great waste of time and resources if a utility were required, as part of a rate increase application, to prove the absence of price discrimination among all wholesale and retail classes and subclasses. Consequently, the Commission placed upon a person alleging price squeeze a requirement to establish a *prima facie* case indicating the likelihood of the existence of a price squeeze. At the same time, the Commission recognized that in any rate increase application the ultimate burden of proof (*i.e.*, the risk of non-persuasion) rests on the utility.

This Commission believes that the concern of the Federal Power Commission in this regard was well placed. Although this Commission's analysis of price squeeze differs in some respects from that of the Federal Power Commission, the basic framework is administratively desirable and legally correct. Accordingly, the burden of establishing a *prima facie* case of price squeeze rests on the person alleging a price squeeze. If a *prima facie* case has been made, the burden of going forward shifts to the filing utility, and the utility bears the burden of proving that a proposed wholesale rate increase is not unduly discriminatory. However, consistent with Commission and judicial interpretation of section 206 of the Federal Power Act, in cases of an initial rate or a complaint filed pursuant to section 206, both the burden of going forward and the burden of proof rest on the person alleging a price squeeze.

In *Missouri Power and Light Company*, Opinion No. 31, (October 27, 1978), the Commission held that a three-part analysis would be applied to its consideration of a price squeeze issue. First, it must be determined whether there is price discrimination against the utility's wholesale customer with respect to rate(s) charged by the utility to its retail customers. Second, if price discrimination is found, it must be determined if there is, or if there is a potential for, an anticompetitive effect. Third, if the anticompetitive effect is also found, then a price squeeze situation exists, and the wholesale rate is considered to be unduly discriminatory, unless the Commission determines that there are countervailing public policy or factual circumstances which would cause the Commission to conclude that the discrimination is not undue. Since sections 205 and 206 of the Federal Power Act prohibit the establishment of a rate that is unduly discriminatory, remedial action must be considered if the discrimination is found to be undue.

The following discussion sets forth the Commission's position, and the rationale for the position, on each aspect of the analysis: price discrimination, anticompetitive effect, and undue discrimination.

A. Price Discrimination

In arriving at its determination as to what constitutes price discrimination,

the Commission had considered defining price discrimination to include only those situations in which service characteristics of the wholesale and retail customers are comparable (similar) and the wholesale rates are higher than the retail rates. However, in *Missouri Power and Light Company*, Opinion No. 31-A (May 16, 1979), the Commission rejected this definition, recognizing that price discrimination can exist in cases where there is no disparity in rates but where the costs of serving wholesale customers are less than the costs of serving retail customers. Therefore, it is necessary to consider the wholesale and retail costs as well as rates to determine whether price discrimination exists. Accordingly, the Commission defines price discrimination as a situation in which the relationship of the wholesale rate to the wholesale costs is greater than the relationship of the relevant retail rate to retail costs. In this context, relationship means either the ratio of rates to costs or the difference between rates and costs. Hence, price discrimination exists if there is similarity of service *(i.e.*, approximately equal costs of service) between the wholesale and retail class and the rates for the wholesale class are higher. Price discrimination also exists if services are not similar but the retail rate is lower in relation to retail costs than the wholesale rate in relation to wholesale costs (where retail and wholesale costs are determined on a consistent basis), including situations in which the wholesale and retail rates are the same, but the costs of serving the wholesale class are less than the costs of serving the retail class.

The Commission believes that this definition is consistent with the *Conway* decision. In *Conway*, the Court was concerned that the price structure of the bulk power supplier resulted in unequal profit margins between wholesale and retail customers; that is, the wholesale customers might be discriminated against in the prices they were charged. An analysis focusing solely on similarity of service and a straight comparison of rates would fail to recognize that although the services may not be strictly similar, the price-to-cost relationships may still result in price discrimination against the wholesale customer. Further, this definition of price discrimination is consistent with price discrimination decisions under the antitrust laws, which have focused not only on differences in prices, but also on the cost-justification for the prices.

Having defined price discrimination, it is necessary to determine which wholesale rate and which retail rate should be compared in order to determine if price discrimination exists. With respect to wholesale rates, the question is whether to use the rate proposed by the utility and made effective subject to refund or the rate determined by the Commission to be just and reasonable but for consideration of the price squeeze issue. With respect to the retail rates, the question is whether to use the proposed retail rate, the effective retail rate subject to refund, or the finally effective retail rate.

In *Southern California Edison*, Opinion No. 62 (August 22, 1979), the Commission held that the "just and reasonable, but for price squeeze" wholesale rate, rather than the proposed wholesale rate, should be the rate compared to the relevant retail rate to determine if price discrimination exists. The "just and reasonable, but for price squeeze" wholesale rate (the preliminary just and reasonable wholesale rate) means the rate which the Commission determines to be just and reasonable after consideration of all issues in the proceeding except the price squeeze issue. This rate is not the final wholesale rate because, under section 205 of the Federal Power Act, the Commission cannot determine a final just and reasonable wholesale rate until it disposes of price squeeze allegations.

The Commission's holding in *Southern California Edison* that the preliminary just and reasonable rate should be used for comparison purposes was based upon ramifications of the Commission's limited "remedial" powers under the

Federal Power Act. That act authorizes the Commission to suspend proposed rates for five months, to make the proposed rates effective subject to refund and to order prospective rate relief. Therefore, the Commission can only correct a situation in which it has determined that price squeeze exists by ordering refunds to the wholesale customer of rates paid in excess of the just and reasonable rate and by adjusting the rates for the future. The Commission does not have authority to grant damages to compensate wholesale customers for loss of business or other anticompetitive effects [1] due to the price discrimination; this relief must be sought in the courts. With respect to the relief that the Commission can provide for excess rates already charged, the Commission will, in any event, order refunds for all rates charged in excess of the preliminary just and reasonable wholesale rate, irrespective of any price squeeze issue. Hence customers will receive all the relief that the Commission can order for charges in excess of that rate.

Therefore, there is no practical benefit to be gained from comparing the proposed wholesale rate, instead of the preliminary just and reasonable wholesale rate, with the relevant retail rate.

For similar reasons, the Commission also held in *Southern California Edison* that the effective retail rate or rates should be used for comparison purposes. Unlike the wholesale rate, however, the effective retail rate could include a proposed or interim retail rate that is being collected subject to refund. This distinction is made because the Commission has no authority to adjust retail rates and cannot determine what adjustments the state commission will ultimately make when the final retail rate is established. The Commission, therefore, must accept whatever retail rate is in effect during the relevant time period for its comparisons. Moreover, it is the effective retail rate with which the wholesale customer must compete for retail customers.[2] Because the effective rate may change during the course of the Commission proceedings, it may be necessary to base the comparison on more than one retail rate.

The Commission wishes to emphasize the importance of the correct selection of the retail class used for comparison. This issue was discussed in depth in *Commonwealth Edison Company*, Opinion No. 63 (September 14, 1979) and Opinion No. 63–A (November 16, 1979). The relevant retail class for price discrimination comparisons consists of the customers for whom there is competition between the bulk power supplier and its wholesale customer. In *Cities of Batavia* v. *F. P. C.*, 548 F. 2d 1056 (D.C. Cir. 1977), the court was concerned about the reasonableness of the composition of a retail class that included all industrials regardless of their individual peak characteristics. The court's concern seemed to be that group subsidies within the industrial class might work to the competitive disadvantage of the wholesale class. For example, a wholesale customer may wish to compete for a part of the industrial class. If that part of the class were charged lower rates than their costs of service would justify because it was being subsidized by the rest of the industrial class whose costs of service were even lower, the wholesale customer would be disadvantaged in competing with the utility for that part of the class. This would be of concern to the Commission if the competition were solely for the subsidized group of customers and not also for the retail customers who provided the subsidy. Accordingly, the Commission believes that the person alleging a price squeeze should specify the group of customers for which competition exists, explain why the specified group was selected for comparison, and explain why other retail groups were not selected. Without this specification and explanation, the

[1] *See* note 3, *infra*, p. 19.

[2] If a final retail rate is determined and refunds ordered during the course of the wholesale proceeding, it is the lower rate that is the effective rate for these purposes.

Commission cannot determine whether the alleged price discrimination with respect to this group has the potential of causing an anticompetitive effect.

In the comparison of the relevant retail group to the wholesale customer(s), the Commission has determined that the average or aggregate class characteristics of the relevant retail and wholesale classes may be used unless the whole class is not the object of competition.

In order to satisfy the price discrimination requirement of a *prima facie* case, the person alleging a price squeeze may make a direct comparison of the relevant wholesale and retail rates, without an examination of the respective costs of service, if the wholesale rate is higher than the retail rate. If the wholesale rate is not higher, the person may satisfy the price discrimination requirement of the *prima facie* case by comparing the price/cost relationships of the two rates. If the price/cost relationship comparison is made, the person alleging a price squeeze need only show, in the *prima facie* case, that certain cost-determining factors indicate that price discrimination exists, without specifically quantifying the costs.

The Commission recognizes that such a minimal showing of costs in the *prima facie* case makes the burden of going forward relatively light, but believes that such a showing is all that should be required in the *prima facie* case, for two reasons: the utility has the burden of proof in wholesale rate increase cases; and the utility possesses, or should be able to develop, the load and cost data needed to make the price/cost comparison. The first factor, the utility's burden of proof, requires that the showings necessary to show price discrimination for purposes of a *prima facie* case be less stringent than the showings necessary to demonstrate price discrimination if the person alleging price squeeze bore the burden of proof. The Commission has been unable to devise a requirement to show costs, for purposes of the price discrimination requirement of the *prima facie* case, which is heavier than the minimal showing and yet which does not, in essence, place the burden of proof on the person alleging the price squeeze.

Further, since any information (including estimates) on retail costs is far more accessible to the utility, the Commission feels that this information should be introduced by the utility after the *prima facie* case has been satisfied, when the utility presents its case to show cost-justification of the relvant rates. In promulgating regulations under section 133 of the Public Utility Regulatory Policies Act (16 U.S.C. 2643, Pub. L. 95-617, November 9, 1978), the Commission discovered that utilities often do not have the load data needed to ascertain with any precision the costs of serving a particular retail class. To the extent that the utilities do not have these data, the person alleging a price squeeze cannot secure it through discovery. However, the utilities do have an understanding of the behavior of the retail class and the bases for retail rate loads and structures. Since it is possible to perform an adequate cost study based on very rough load estimates, and since the utility is in a far better position to make these estimates, the Commission believes that the practical way of proceeding is to place on the utility the task of quantifying the cost differences. After the utility presents its case, the person alleging price squeeze will be required to rebut the utility's showing that the difference in rates is cost justified, in order to prevail on the merits.

In addition, the Commission feels that the requirement in the *prima facie* case to show that the price discrimination is of sufficient magnitude and duration so as to reasonably indicate an anticompetitive effect, discussed below, makes the burden of going forward sufficiently stringent to preclude frivolous claims. The Commission specifically requests comments on this subject.

The Commission does not require the use of any particular methodology to

prove or disprove price discrimination. Possible methods include, but are not limited to, the following: wholesale versus retail average revenues: application of retail rates to wholesale billing determinants (so long as the ratio of billing demands to allocation demands of the retail group is similar to that of the wholesale group or an adjustment is made to put the two groups on the same basis); comparison of revenues at various load curves; comparison of overall rates of return; and the transfer price analysis. Each of these methods has advantages and disadvantages. The Commission will determine whether the method employed in any particular proceeding was sufficient to demonstrate price discrimination, based upon the record of that proceeding.

If, in presenting its case, a utility offers a rate of return analysis demonstrating that there is not a lesser rate of return on the relevant retail class than on the wholesale class, this demonstration will constitute an affirmative defense.

However, in attempting to prove that a difference in rates is cost-justified, a utility should assure that any cost comparisons it presents compute costs on the wholesale and retail side in the same manner and, to the extent possible, in the manner followed by the Commission. Without such synchronized computations, it may be difficult for the Commission to draw meaningful conclusions from the data presented. (*Southern California Edison Company.*) In addition, as the Commission stated in *Southern California Edison* and in *Commonwealth Edison Company*, cost differences should be quantified; that is, the utility should show how much of the difference in rates is accounted for by the different cost factors. A generalized showing is insufficient. However, if the utility lacks the requisite data on costs of serving the relevant retail class, it may use estimates in performing its full cost study.

B. Anticompetitive Effect

If price discrimination is established, the Commission must determine whether there has been, or could be, an anticompetitive effect. In this regard, two concepts, competition and anticompetitive effect, require consideration and definition. Although the two terms are necessarily related, it is important to consider each one separately and to determine the type of showing, if any, which is required to establish its existence.

In *Connecticut Light and Power Company*, Docket No. ER78-517 (August 20, 1979), the Commission reiterated the assumption that it had stated in *Missouri Power and Light*, Opinion No. 31-A, that the electric industry is an industry in which competition exists. In *Connecticut*, the Commission concluded that the concept of competition in the electric industry should not be confined to cases in which active rivalry among alternative suppliers can be demonstrated. The characteristics essential to the existence of competition are geographic proximity and the ability of the wholesale customer and the filing utility to be alternative suppliers of the same product for an individual customer or group of customers. Accordingly, the Commission held in *Connecticut* that the only showing required for the establishment of a *prima facie* case as to competition is that the wholesale customer and the filing utility are in geographic proximity and that they are or could be alternate suppliers. The Commission stated that such a showing could be challenged.

The Commission recognizes that if the relevant form of competition is franchise competition, certain requirements of the *prima facie* case may not be precisely applicable. This is so because franchise competition involves competition for all types of electric service. There is no single retail rate that corresponds to all types of retail loads. Consequently, those elements of a *prima facie* case which require specification of the effective retail rate schedule and a comparison of the effective retail rate with the relevant wholesale rate are difficult to establish when franchise competition is alleged. The Commission intends that the presiding judge would

take this difficulty into consideration when determining whether the person alleging price squeeze has met the burden of going forward on the price squeeze issue.

In *Connecticut*, the Commission also decided that the person alleging price squeeze must allege the form of competition which was purportedly being harmed. Competition for individual customers or customer groups, franchise competition and fringe area competition were all held to be relevant forms of competition. The requirement of alleging the form of competition involved was imposed to aid the utility in the event that it seeks to rebut the showing of competition.

In *Connecticut* the Commission considered whether a person alleging price squeeze must show actual anticompetitive effect due to the alleged price discrimination or whether a showing of a potential anticompetitive effect is sufficient. The antitrust laws and federal case law on the subject [3] have stated that the concern of Congress in passing the antitrust laws was with "probabilities not certainties" and that the intent is to "reach such discriminations in their incipiency." However, the courts have also made clear that "potential" does not refer to a "mere possibility", but rather to a "reasonable probability". *See, e.g., Brown Shoe Co.* v. *United States*, 370 U.S. 294 (1962); *Corn Products Refining Co.* v. *Federal Trade Commission*, 324 U.S. 726 (1945); and *Forgett* v. *Scharf*, 181 F.2d 754 (3d Cir.), *cert. denied*, 340 U.S. 825 (1950). The Commission further held in *Connecticut* that if the *prima facie* requirements of competition and price discrimination are satisfied, it is reasonable to presume that there is a potential anticompetitive effect, subject to the utility's right to rebut this presumption.

Even though a rebuttable presumption of anticompetitive effect has been established with respect to the case-in-chief, the Commission believes that, in order to meet its burden of going forward in the *prima facie* case, a person alleging price squeeze should be required to show that the price discrimination is of sufficient magnitude that an anticompetitive effect is indicated. Further, the Commission believes that, if more than one retail rate has been in effect during the pendency of the wholesale rate proceeding, the person alleging price squeeze should be required to show that the price discrimination with respect to each effective retail rate that is alleged to cause discrimination is of sufficient magnitude and duration that an anticompetitive effect is indicated. Duration in this context refers to the time period during which the proposed wholesale rate and the effective retail rate (or rates) are in effect concurrently. The purpose of these requirements in the *prima facie* case is, in view of the minimal showings required to meet the *prima facie* requirement on price discrimination, to preclude the possibility of a utility's being forced to defend against a frivolous claim. The Commission recognizes that the duration requirement may be difficult to show in an unphased proceeding. Section 35.30 provides that any participant may submit pleadings in support of, or in opposition to, the *prima facie* case, thus providing the utility with the opportunity to argue that the price discrimination is so small or short-lived that there is no potential for an anticompetitive effect. The presiding judge has the authority to determine that the *prima facie* case has not been satisfied because the potential for an anticompetitive effect is *de minimis*.

The Commission specifically asks for comments on the advisability of including in the *prima facie* case a statement or demonstration by wholesale customers that they cannot secure like power from an alternative source at an ultimate price equal to or lower than the price which their current bulk power supplier would be charging

[3] The Commission does not have the responsibility to enforce the antitrust laws. It does, however, consider the policies underlying those laws in carrying out its regulatory responsibilities.

absent price discrimination. It would appear that a bulk power supplier's price discrimination would have no anticompetitive effect if the customer could avoid having to pay the discriminatory price. Of course, if the alternative bulk power supplier is not directly interconnected with the customer, then the willingness of intervening systems to wheel and the price at which they would do so, as well as the reliability of the service or the assurance of continued supply, would have to be taken into account.

The proposed rule contains no mention of this consideration. Nonetheless, a utility could include a showing of the availability of alternative power at a suitable price in its case in response to a price squeeze allegation so as to rebut any presumption of anticompetitive effect. It might be considered more appropriate, however, for the party alleging price squeeze to make a statement of showing that appropriately-priced power from an alternative source is not available. One of the factors militating towards placing this obligation on the party alleging price squeeze is the Commission's belief that wholesale customers should be continually testing the market and searching for cheaper or more reliable sources of power. It follows from this assumption that the wholesale customer would be in a better position to describe its bulk power supply alternatives than would the present bulk power supplier. On the other hand, raising this consideration in every price squeeze proceeding through its inclusion in the *prima facie* case may add a great deal to the time and expense of these proceedings, and the Commission may ultimately conclude that these resources have been wasted because this consideration is of no importance in the great majority of cases. The Commission requests comments on whether such a showing should be made as part of a price squeeze case; on the which party should be required to make such a showing; and on what type of evidence should constitute the demonstration.

The final consideration pertaining to anticompetitive effect is whether the ownership characteristics of the wholesale customer are relevant to a determination of anticompetitive effect. In *Boston Edison Company*, Opinion No. 809-A (December 9, 1977), the Commission specifically posed the question, "In determining the existence of anticompetive effect, what significance is there, if any, that publicly-owned utilities may be involved?" In *Commonwealth Edison Company*, the Commission found that it was irrelevant that a wholesale customer may be a municipality or a cooperative and may therefore have some tax or other advantages which are not available to the filing utility. Any competitive or other advantages that have been accorded to municipalities or cooperatives have been granted by the Congress or the state legislatures. Regulation should not reverse legislative intent.

Furthermore, in *Southern California Edison* the Commission noted that the crucial element in a price squeeze case is that the wholesale rates are discriminatory. Whether a wholesale customer has or has not been forced to pass these higher costs on to its customers is immaterial to a finding of price squeeze, since the impairment of the municipal customer's retail competitive advantages would itself be an anticompetitive effect.

C. Undue Discrimination

If the Commission determines that there is price discrimination and a potential for an anticompetitive effect, there is price squeeze. A rebuttable presumption then arises that the wholesale rate is unduly discriminatory. The Commission shall find that the price squeeze constitutes undue discrimination, unless countervailing public policy or factual considerations cause the Commission to conclude that the discrimination is not undue. *Missouri Power and Light Company*, Opinion No. 31. Such considerations include, but are not limited to: adequacy

of service, reliability, financial integrity, the length of time the price squeeze existed, the extent of price discrimination, and regulatory actions and policies of state commissions.

With respect to the regulatory actions and policies of state commissions, many utilities have claimed that, even if the effective retail rate is discriminatorily low when compared with the wholesale rate, price squeeze cannot be found because the low retail rate was set by the state public service commission ("the state action doctrine"). In *Parker v. Brown*, 317 U.S. 341 (1943), the Supreme Court held that the actions of state officials which would violate the antitrust laws if carried out by private persons are not violative of the Sherman Act if done according to the direction of the legislature. The Commission has determined that the "state action doctrine" cannot be relied upon as an absolute defense in cases in which all or a part of the discrimination is due to differing regulatory policies. As the Commission noted in *Southern California Edison*, the doctrine does not necessarily grant immunization in every case in which part of the discrimination can be traced to action of the state. To be granted such immunity, the action of the state must be so dominant as to make it unfair to hold the utility liable. If, however, it is found that the conflicting regulatory policies of the Commission and the state commissions have caused the price squeeze, it may well be concluded that the discrimination is not undue.

In *Missouri Power and Light Company*, Opinion No. 31, the Commission held that the filing utility's intent to discriminate in order to gain competitive advantage was irrelevant to a determination of price squeeze, as well as to any determination made regarding the correction of price squeeze. The Federal Power Act, as interpreted by *Conway*, requires the Commission to consider the existence of undue discrimination between retail and wholesale service in setting a just and reasonable rate regardless of whether or not that discrimination was intentionally imposed. Therefore, no showing of intent to create a price squeeze is required.

As previously noted, under the Federal Power Act, the Commission's only mechanisms for correction are the ordering of refunds and prospective rate relief. However, as stated in *Conway*, refunds can go beyond the Commission's normal cost of service adjustments at least to the lower end of the "zone of reasonableness."

III. Summary of the Proposed Regulations

The proposed rule incorporates the Commission's decisions and conclusions explained above. This section of the preamble discusses the specific provisions of the proposed rule.

Paragraph (a) of proposed § 35.32 provides that this section sets forth the substantive provisions applicable to Commission proceedings involving the determination of a price squeeze issue pertaining to electric utilities.

Paragraph (b) contains definitions applicable to this section and to new § 35.30. This paragraph defines the following terms: "anticompetitive effect", "competition", "franchise competition", "price discrimination", "phase", "preliminary just and reasonable wholesale rate", and "price squeeze". Several of these terms will be discussed below in the context of the paragraphs which use the terms.

Paragraph (c) provides that a person alleging price squeeze must support its allegations by filing a *prima facie* case. Subparagraphs (1) through (4) of pargraph (c) establish the requirements of a *prima facie* case, which requirements must be met if consideration of the price squeeze issue is to continue.

Subparagraph (1) of paragraph (c) sets forth the first requirement of the *prima facie* case, which is the specification of the utility's effective retail rate schedule or schedules which the person alleges is relevant to the price squeeze.

Subparagraph (2) of paragraph (c) establishes the second requirement of the *prima facie* case, which is a showing that there is enough evidence that price

discrimination exists to warrant going forward with the proceeding. Consistent with the definition of price discrimination in paragraphs (b)(2), paragraph (c)(2)(ii) establishes that a person alleging price squeeze must show price discrimination in one of three ways as part of the *prima facie* case. Subparagraph (2)(ii)(A) or paragraph (c) provides that price discrimination may be shown by demonstrating that the wholesale rate is higher than the utility's retail rate for the relevant group of customers. Subparagraph (2)(ii)(B) provides that, if the wholesale rate is equal to the utility's retail rate for the relevant group of customers, price discrimination may be shown by demonstrating that there is a reasonable indication that the costs of serving those retail customers are greater than the costs of serving the wholesale customer. Finally, subparagraph (2)(ii)(C) provides that, if the wholesale rate is less than the utility's retail rate for the relevant group of cutomers, price discrimination may be shown by demonstrating that there is a reasonable indication that the costs of serving those customers are sufficiently greater than the costs of serving the wholesale customer, so that price discrimination exists against the wholesale customer. Accordingly, for purposes of the *prima facie* case, the person alleging price squeeze may demonstrate price discrimination by submitting a straight rate comparison on the assumption that the costs to serve the wholesale and retail customers are similar or by submitting a price/cost comparison for the wholesale and retail customers, respectively. If the price/cost comparison is made, the person alleging a price squeeze need only show, in the *prima facie* case, that one or more cost determining factors indicate that price discrimination exists, without specifically quantifying the costs. For example, in subparagraphs (2)(ii)(B) and (C), the person alleging price squeeze could show that distribution costs for the relevant group of retail customers were sufficiently high that, if the rates were adjusted to account for distribution costs, the wholesale rate would be higher than the retail rate.

Section 2.17 requires "as showing that the retail rates are lower than the proposed wholesale rate for comparable service," as one of the elements of a *prima facie* case. The proposed rule differs from § 2.17 in that the person alleging price squeeze under the proposed rule has the latitude to show price discrimination when service is not similar.

Subparagraph (2)(i) of paragraph (c) establishes the rates which are to be compared for purposes of the *prima facie* showing of price discrimination under subparagraph (2)(ii). Subparagraph (2)(i) provides that if the proceeding is phased in accordance with § 35.30, the effective retail rate shall be compared with the wholesale rate which the Commission determines to be just and reasonable after consideration of all issues in the proceeding except price squeeqe (the "preliminary just and reasonable wholesale rate," defined in paragraph (b)(7)). If the price squeeze issue is not to be considered in a separate phase, subparagraph (2)(i)(B) provides that the effective retail rate shall be compared with the proposed wholesale rate. In that situation, the rate used for comparison in the Commission's final decision will be the wholesale rate as adjusted by determinations on issues other than price squeeze.

Subparagraph (3) of paragraph (c) establishes the third requirement of a *prima facie* case, consisting of a showing that competition exists between the utility and the wholesale customer, a statement of the form of competition which is being harmed, and the specification and explanation of the group of customers for which competition exists. The person alleging price squeeze must show that competition exists by showing that the wholesale customer is in geographic proximity to the electric utility and that the wholesale customer is, or could be an alternate supplier to the group of customers. The person must also state whether the purported competition is franchise competition (defined in

paragraph (b)(5)) or competition for individual customers, including fringe areas. The subparagraph further requires that the person alleging price squeeze identify the specified group or groups of customers for whom the type of competition exists and explain the basis of the determination that the specified group is the object of competition and other retail groups are not.

The proposed rule differs from § 2.17 in that the proposed rule requires only a showing of geographic proximity and that the customer is or could be an alternative supplier of electricity to the relevant customers. The proposed rule also contains the additional showings relating to the form of competition involved and the customers who are the object of the competition, which were not required by § 2.17.

The fourth requirement of the *prima facie* case is set forth in paragraph (c)(4) which states that the person alleging a price squeeze must show that the magnitude, and in certain cases the duration, of the price discrimination indicate that there is a potential for an anticompetitive effect.

The final requirement of the *prima facie* case is established in paragraph (c)(5) which provides that the person alleging price squeeze must indicate the reduction in the wholesale rate which is necessary to eliminate the price squeeze. The proposed rule is similar to § 2.17 in this respect.

As part of a *prima facie* case, § 2.17(a)(4) requires a showing of "the wholesale customer's prospective rate for comparable service, i.e., the rate necessary to recover bulk power costs (at the proposed wholesale rate) and distribution costs." This requirement has not been included in the proposed rule, because the Commission has determined that, consistent with its decision as to the ownership characteristics of the wholesale customer, it is irrelevant to a determination of price squeeze.

The requirements of the *prima facie* case in § 2.17 are more stringent than the ones contained in the proposed rule, both with respect to the price discrimination and the competition showings. As the Commission noted in *Connecticut Light and Power*, the minimal showing of competition now necessary should shift the focus in price squeeze cases from proving competition to showings on the price discrimination issue. For this reason, the Commission cautions against exclusive reliance on the price discrimination aspect of the *prima facie* case by the person alleging price squeeze. More may be required of the person in cases in which the utility offers evidence in its case that the rates are not unduly discriminatory.

Paragraph (d) establishes that in proving or disproving price discrimination in the *prima facie* case or in the full case, the Commission does not require the use of any particular methodology.

Paragraph (e) provides that certain rebuttable presumptions arise from the satisfaction of certain of the requirements of the *prima facie* case. Subparagraph (1) of paragraph (e) provides that if the requirements of the *prima facie* case as specified in paragraph (c) are satisfied, a rebuttable presumption arises that price discrimination with an anticompetitive effect (price squeeze) exists.

Subparagraph (2) of paragraph (e) establishes that, if price squeeze is found, a presumption arises that the rate is unduly discriminatory. In determining whether the wholesale rate is unduly discriminatory, the Commission may consider countervailing public policy and factual considerations, including: adequacy of service, reliability, financial integrity, length of time the price squeeze existed; the extent of the price squeeze; and the regulatory actions and policies of state commissions.

Paragraph (f) sets forth provisions applicable to the utility's case. Subparagraph (1) provides that if the utility's case is based upon the difference in the costs of serving the retail and wholesale customers, the utility must quantify the differences in its total costs, including distribution costs, if any, between the wholesale and pertinent retail services. However, as

discussed above, if the utility lacks the requisite data on costs of serving the relevant retail class, it may use estimates in performing its full cost study. Subparagraph (2) sets forth the affirmative defenses available to the utility. Clause (i) establishes that, if the utility presents a rate of return analysis that shows that the rate of return for the pertinent retail service or services is not lower than the rate of return on the pertinent wholesale service or services, that showing shall constitute an affirmative defense. Clause (ii) provides that, if the utility can show that the wholesale customer could not be an alternative supplier to the utility for the group of customers who are the object of the competition, that showing shall constitute an affirmative defense.

Paragraph (g) establishes which participant in the proceeding bears the burden of proof. Subparagraph (1) provides that in the case of a proposed wholesale rate increase, if a *prima facie* case has been made in accordance with paragraph (c) and § 35.30, the utility shall bear the burden of proof to justify the wholesale rate as not unduly discriminatory. In contrast, subparagraph (2) places the burden of proof on the person alleging price squeeze in the case of an initial rate filed under § 35.12 and in the case of a complaint proceeding conducted pursuant to section 206 of the Federal Power Act.

Paragraph (h) provides that a finding of undue discrimination shall require remedial action by the Commission.

IV. Application of Regulations to Proceedings to the Natural Gas Industry

Commission proceedings in which price squeeze has been an issue have been almost exclusively proceedings involving the electric utility industry. Accordingly, the proposed rule would pertain only to the electric industry. However, the Commission specifically solicits comments from members of the public on whether the regulations contained in the proposed rule should also be made applicable to the natural gas industry.

V. Public Comments and Public Hearing

The Commission invites interested persons to submit written data, views, and other information with respect to the matters set forth in this notice. All comments should be verified and should reference Docket No. RM79–80 and should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. An original and 14 conformed copies should be filed. All comments received by December 24, 1979, will be considered by the Commission prior to promulgation of the final regulations.

All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

The Commission intends to conduct a public hearing on the matters contained in this notice and in the companion notice (Docket No. RM79–79). The members of the panel at that hearing will be designated by the Chairman of the Commission. The date, location and procedures will be announced in the near future.

(Federal Power Act, 16 U.S.C. § 791–828c; Department of Energy Organization Act, 42 U.S.C. § 7101–7352; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission is proposing to amend Part 35 of Chapter 1, Title 18, Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 35—FILING OF RATE SCHEDULES

1. Part 35 is amended in the table of contents by adding in the appropriate numerical order a heading for § 35.30 to read as follows:

§ 35.32 Price squeeze—Substantive rules.

2. Part 35 is further amended by adding a new § 35.32 to read as follows:

§ 35.32 Price squeeze—substantive rules.

(a) *Applicability.* This section sets forth the substantive provisions applicable to Commission proceedings involving the determination of a price squeeze issue pertaining to electric utilities.

(b) *Definitions.* For purposes of this section and § 35.30, the following definitions apply.

(1) "Price squeeze" means price discrimination between a utility's wholesale and retail rates with an anticompetitive effect.

(2) "Price discrimination" means that the relationship of the wholesale rate to the wholesale costs is greater than the relationship of the relevant retail rate to the retail costs. "Relationship" means either the ratio of rates to costs or the difference between rates and costs.

(3) "Anticompetitive effect" means the actual or potential impairment, as a result of price discrimination on the part of an electric utility, of the utility's wholesale customer's ability to make sales of the same or similar products to a retail customer or type of retail customer that could also be served by the utility. "Potential" means a reasonable probability, not a mere possibility.

(4) "Competition" means the actual or potential ability of an electric utility and its wholesale customer to serve as alternate suppliers of the same or similar products to the same retail customer or type of retail customer.

(5) "Franchise competition" means the right to provide electric service to all customers in an entire area.

(6) "Phase" means a portion of a proceeding in which only certain issues in the proceeding are considered or in which certain issues in the proceeding are excluded from consideration.

(7) "Preliminary just and reasonable wholesale rate" means the wholesale rate that is found to be just and reasonable by the Commission after completion of the phase or phases preceding the price squeeze phase of the proceeding.

(c) *Prime facie case.* Except as provided in § 35.30(h)(8), any person alleging a price squeeze under this section must support the allegation by filing a *prime facie* case, which shall include the items listed in subparagraphs (c)(1) through (c)(4) of this paragraph.

(1) The person shall specify the utility's effective retail rate schedule or schedules that the person alleges are relevant to the issue of price squeeze.

(2) The person shall submit evidence on price discrimination in accordance with paragraphs (c)(2)(i) and (c)(2)(ii) of this subparagraph.

(i) The person shall compare the effective retail rate or rates with:

(A) The preliminary just and reasonable wholesale rate, if the price squeeze issue is to be considered in a separate phase in accordance with § 35.30;

(B) The proposed wholesale rate, if the price squeeze issue is not to be considered in a separate phase of the proceeding, in accordance with § 35.30, but the Commission's final decision will be based on the wholesale rate as adjusted by its cost of service determinations.

(ii) The person shall demonstrate that:

(A) The wholesale rate is higher than the utility's retail rate for the group of retail customers who are the object of competition;

(B) If the wholesale rate is equal to the utility's retail rate for the group of retail customers who are the object of competition, there is a reasonale indication that the costs of serving those retail customers are greater than the costs of serving the wholesale customers;

(C) If the wholesale rate is less than the utility's retail rate for the group of retail customers who are the object of competition, there is a reasonable indiction that the costs of serving those retail customers are sufficiently greater than the costs of serving the wholesale customer that there is price discrimination against the wholesale customer.

(3) The person shall submit evidence on competition in accordance with

paragraphs (c)(3)(i) and (c)(3)(ii) of this subparagraph.

(i) The person shall demonstrate the existence of competition by showing:

(A) That the wholesale customer is in geographic proximity to the utility; and

(B) That the wholesale customer is or could be an alternative supplier of electricity to the group of retail customers (a retail class or a part of a retail class) for which there is competition.

(ii) The person must also:

(A) State whether the purported competition is franchise competition or competition for individual customers, including fringe areas; and

(B) Specify the group of customers for which there is competition, explaining why the specified group was determined to be the object of the competition and why other retail groups were not.

(4) The person shall show that the magnitude of the price discrimination indicates that there is a potential for an anticompetitive effect. If more than one retail rate has been in effect during the pendency of the wholesale rate proceeding, the person shall state the magnitude and duration of the price discrimination with respect to each effective retail rate which is alleged to cause the discrimination and show that the magnitude and duration of the price discrimination under such retail rate or rates is sufficient to indicate that there is a potential for an anticompetitive effect.

(5) The person shall indicate the reduction in the wholesale rate which is necessary to eliminate the alleged price discrimination.

(d) *Methodology to show price discrimination.* No particular methodology shall be required to be used to demonstrate the presence or absence of price discrimination.

(e) *Rebuttable presumptions.* The following rebuttable presumptions exist.

(1) If the *prima facie* has been made in accordance with paragraph (c) and § 35.30, a rebuttable presumption arises that price discrimination with an anticompetitive effect (price squeeze) exists.

(2) A finding of price squeeze shall create a rebuttable presumption that the wholesale rate is unduly discriminatory. In determining whether the wholesale rate is unduly discriminatory the Commission may consider countervailing public policy and the factual circumstances.

(f) *Utility's case.* This paragraph is applicable to the utility which filed the proposed rates under § 35.13 or § 35.12 or whose rates are the subject of the proceeding conducted pursuant to section 206 of the Federal Power Act.

(1) If the utility's case is based in part or in whole upon the difference in the costs of serving the retail and wholesale customers, the utility must quantify the differences in total costs, including distribution costs, if any, between the wholesale and pertinent retail services.

(2) The following showings constitute affirmative defenses for the utility.

(i) If the utility presents a rate of return analysis that shows that the rate of return for the pertinent retail service or services is not lower than the rate of return for the pertinent wholesale service or services, that showing shall constitute an affirmative defense.

(ii) If the utility shows that the wholesale customer could not be an alternative supplier to the utility for the group of customers who are the object of the competition, that showing shall constitute an affirmative defense.

(g) *Burden of proof.* (1) In the case of a proposed wholesale rate increase, if a *prima facie* case has been made in accordance with paragraph (c) and § 35.30, the utility shall have the burden of proof (*i.e.*, the risk of nonpersuasion) to justify that the wholesale rate is not unduly discriminatory.

(2) In the cases of an initial rate filed under § 35.12 or of a complaint proceeding conducted pursuant to section 206 of the Federal Power Act, the person alleging price squeeze shall have the burden of proof to show that the wholesale rate is unduly discriminatory.

(h) *Remedy.* A finding of undue discrimination shall require such remedial action as the Commission deems appropriate.

¶ 32,047 Statement of Policy on Distributor Access to Outer Continental Shelf Gas

44 F. R. 67166 (November 23, 1979).

18 CFR Parts 280 and 284

[Docket No. RM80-11]

Statement of Policy on Distributor Access to Outer Continental Shelf Gas; Proposed Rulemaking

Issued: November 16, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Section 603 of the Outer Continental Shelf Lands Act Amendments of 1978 requires the Commission to promulgate a statement of general policy concerning the transportation of natural gas owned by a local distribution company from an outer continental shelf lease to the service area of the local distribution company. The proposed rule specifies the application procedures, forms of authorization, and terms and conditions which would apply to such transportation.

DATES: Written Comments by December 10, 1979. Public Hearing on December 10, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (Reference Docket No. RM80-11).

FOR FURTHER INFORMATION CONTACT:

Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8454.
Charles W. Strotman, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-9028.

I. Discussion

On September 18, 1978, the Outer Continental Shelf Lands Act Amendments of 1978 (OCSLAA), Pub. L. 95-372, 43 U.S.C. 1801, *et seq.*, became law. Section 603 of the OCSLAA requires the Commission to promulgate a statement of general policy concerning the transportation of natural gas owned by a local distribution company from an Outer Continental Shelf (OCS) lease to the service areas of the local distribution company.

Traditionally, local distribution companies have relied upon pipeline system supplies to meet their requirements. However, as curtailment deepened on interstate pipelines during the 1970's, many local distribution companies were forced to resort to expensive "self-help" measures in order to protect their high priority users. Local distribution companies frequently incurred substantial take-or-pay obligations when contracting for supplemental supplies. In addition, supplemental facilities such as LNG peak shaving plants and SNG plants require extensive capital investment. Further, those measures included purchasing imported LNG or SNG made from imported oil, and the purchase of such supplemental supplies contributes to the nation's balance of payments problems. In contrast, the direct investment in domestic OCS reserves (OCS gas) permits the local distribution companies to obtain secure supplemental supplies while avoiding many of the adverse consequences of alternative investments.

Permitting local distribution companies to have the option of investing some of their available capital in the development of OCS gas is consistent with the public interest. This would assure that the high priority markets served by local distribution companies will have access to domestic energy supplies developed from the public lands. This Notice of Proposed Rulemaking presents the Commission's views on a desirable long term policy regarding local distribution company

participation in the development and production of OCS gas. This Notice also discusses a series of issues that arises from local distribution company participation in the OCS.

A. Advance Notice of Policy

Section 603 of the OCSLAA was prompted by the uncertainty that surrounds the terms upon which local distribution companies can develop their own OCS reserves. This uncertainty deters local distribution companies from investing in OCS exploration and development efforts. Because investment decisions must be made far in advance of the actual commencement of any transportation arrangements, the Commission will clarify the future availability of transportation of OCS gas to local distribution companies by providing a description of the eligibility criteria, limitations and conditions which the Commission will attach to the transportation.

The only recent case which authorized the transportation of local distribution company produced OCS gas illustrates the Commission's policy to date on the transportation of such natural gas. Initially, the Commission denied an application for a transportation certificate, citing the greater need of the transporting pipeline's customers over the local distribution company's customers.[1] The comparative end-use of the two sets of customers was the basis for assessing the public convenience and necessity of the proposed transaction. On rehearing, the transportation was authorized subject to the diversion of the OCS gas into the system supplies of the transporting pipelines, if needed to avoid irreparable injury to life or property.[2]

The enactment of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. 95-621, 15 U.S.C. § 3301 *et seq.*, has alleviated many of the concerns that prompted the Commission's imposition of certificate conditions in the above case. First, the general curtailment outlook for interstate system supplies has improved.[3] Second, local distribution companies served by interstate pipelines may now purchase significant volumes of natural gas from the intrastate market under sections 311(b) and 312 of the NGPA. Third, section 311(a) of the NGPA provides the Commission with greater flexibility in authorizing transportation on behalf of local distribution companies than available under the Natural Gas Act. In light of these changes, the Commission need not continue a restrictive policy which was adopted to mediate between competing demands for a limited supply of natural gas available to the interstate market.

The Commission proposes to instead focus its future policy upon the objective of placing local distribution companies on a more equal footing with other purchasers of natural gas supplies. Local distribution companies should not be at a disadvantage in the exploration and development of OCS gas.

B. Statutory Authority for Transportation

When the OCSLAA was enacted, section 7 of the Natural Gas Act was the Commission's only basis for authorizing transportation in interstate commerce. However, section 311(a) of the NGPA gave the Commission an additional basis for authorizing transportation arrangements. Given the superseding enactment of the NGPA, the Commission considers the use of section 311(a) of the NGPA to be consistent with

[1] Trunkline Gas Company, Order issued January 11, 1977 in Docket No. CP74-322, *et al.* (Trunkline was transporting OCS gas produced by Northern Michigan Exploration Co. to its parent, Consumers Power Company.)

[2] Order Granting Rehearing and Granting Certificates of Public Convenience and Necessity, Docket No. CP74-322, *et al.*, issued November 10, 1977.

[3] Commission Staff Reports on Impact of 1979-1980 Winter Curtailment for Twenty-Eight Pipeline Companies, Docket No. TC79-04, *et al.*, November 1979.

the legislative intent of both the OCSLAA and NGPA. Because the NGPA did not specifically amend section 603 of the OCSLAA, the Commission is prepared to utilize both section 311(a) of the NGPA as well as section 7(c) of the Natural Gas Act to authorize those transactions. Because of the greater flexibility afforded by section 311(a) of the NGPA, the Commission prefers to use that section to implement the transportation specified in section 603 of the OCSLAA rather than section 7(c) of the Natural Gas Act. The selection of either legal authority is left to the applicant.

C. Pipeline Participation

The Commission is aware that the entry of local distribution companies into the competition for OCS leases changes their traditional relationship with interstate pipelines. Although the awarding of OCS leases is the responsibility of the Department of the Interior and not the Commission, the allocation of the limited capacity of interstate pipeline lies within the scope of our concerns.

Section 603(b)(1) of the OCSLAA refers to "the application of any local distribution company." Some commentators may argue that this phrase implies that the local distribution company may apply to the Commission for a certificate without the consent of the transporting pipeline. However, neither the statute nor the legislative history explain the local distribution company's role as a certificate applicant.

The Commission invites comment upon the Commission's authority to grant otherwise eligible applications which are filed by a local distribution company without the concurrence of a transporting onshore interstate pipeline. Some onshore interstate pipelines have excess capacity which, although not being utilized to meet the needs of current customers, is being paid for by the pipeline ratepayers. The transportation of OCS gas on behalf of local distribution companies offers onshore interstate pipelines an opportunity to utilize unused capacity and to reduce the burden upon their ratepayers.[4] If an interstate pipeline is unwilling to avail itself of such opportunities, the question arises whether this Commission can compel the transportation and, if so, under what terms and conditions as will assure that the present and future convenience and necessity is served.

It should be noted, in contrast, that section 5 of the Outer Continental Shelf Lands Act,[5] gives the Commission authority to require offshore pipelines to transport OCS gas owned by local distribution companies on the same basis as OCS gas owned by interstate pipelines. The Commission invites comment upon possible means of resolving disputes between local distribution companies that seek to develop supplemental OCS supplies and interstate pipelines which do not wish to transport the OCS gas. In particular, the Commission invites comment upon the use of the Commisson's authority under section 7(a) of the Natural Gas Act to compel pipeline participation.

D. Term

Because of the local distribution company's need to amortize exploration and development costs, the term of most covered transportation arrangements will probably exceed two years. The proposed rule does not affect the term provisions which apply generally to transportation authorized under section 311(a) of the NGPA. Such transportation is authorized for a two year term on a self-implementing basis.[6] Longer term transportation arrangements are permitted only with prior Commission approval.[7]

The Commission will consider applications for certificates

[4] Section 284.103(d) requires revenues in excess of out-of-pocket costs to be flowed through to the ratepayers in Account 191.

[5] Pub. L. 83-212, 43 U.S.C. § 1334, as amended by section 204 of the OCSLAA.

[6] 18 C.F.R. § 284.104(b). Such arrangements are subject to renewal under § 284.105.

[7] Section 284.107.

authorizations of either a fixed or indefinite term under section 7(c).

E. Incremental Pricing

All first sales of OCS gas are subject to the incremental pricing provisions of Title II of the NGPA. Section 204(c)(4) of teh NGPA requires a local distribution company which purchases OCS gas in a first sale to be treated as an interstate pipeline for the purpose of computing the incremental pricing of the natural gas. To the extent that the local distribution company produces natural gas without creating a separate affiliate, the natural gas would not be subject to incremental pricing.

F. End Use Restrictions

As discussed in Section A, *supra*, the Commission in the past has conditioned the transportation of OCS gas upon diversion into the system supply of the transporting pipeline when needed to serve high priority requirements. However, the President's authority during declared natural gas supply emergencies under Title III of the NGPA removes the need for such conditions. Instead, the OCS gas transported pursuant to this subpart will be outside the scope of the transporting pipeline's curtailment plan. Such an approach is in accord with the legislative history of section 603 of the OCSLAA:

> The ad hoc committee's report points out the need to insulate this gas from the curtailment system of the interstate pipeline which transports this gas in order that the local distribution company can justify the investment in developing its own resources on the grounds that it will be assured of receiving the gas. Under present law, this result is already reached.[9]

The Commission invites comment upon the treatment of these volumes during declared natural gas supply emergencies.

II. Section-by-Section Analysis

Section 280.101

This section is amended to include a definition of the abbreviation "OCS."

Section 284.240

This section emphasizes the fact that the natural gas transported under Subpart H must be for a local distribution company's general system supply.

Only transportation of the natural gas by interstate pipelines is covered. (By virtue of section 601(a)(1)(B)(ii) of the NGPA, no Commission authorization is required for the sale of the natural gas from a new OCS lease to the local distribution company.) Although Subpart H describes the Commission's policy, the subpart does not authorize any transportation independent of other regulations.

Section 284.242

The definition of "eligible recipient" in proposed paragraph (c) describes who is eligible to participate in the program. Because the definition of local distribution company in section 603(c)(1) of the OCSLAA is different from that in section 2(17) of the NGPA, the term "eligible recipient" is defined to reflect the section 603 definition. It should be noted that if an eligible recipient does not also qualify as either a local distribution company or an intrastate pipeline, within the meaning of the NGPA, transportation cannot be authorized on its behalf under section 311(a) of the NGPA. Covered transportation outside the scope of section 311(a) would have to be authorized by a certificate issued pursuant to section 7(c) of the Natural Gas Act.

Section 603 of the OCSLAA is limited to OCS lease interests owned by local distribution companies. Under the proposed rule, the lease must be owned by either the local distribution company

[9] 124 Cong. Record at H205, January 25, 1978.

itself, a producing affiliate of the local distribution company, or a joint venture in which the local distribution company participates. (The local distribution company may participate in a joint venture through an affiliate.) Any sale between the lease holder and the eligible recipient is a "first sale" under the NGPA. If the eligible recipient produces the OCS gas, then § 270.203(b) governs the first sale status of any sales made by the eligible recipient.

The proposed definition of "eligible OCS natural gas" in paragraph (d) would include all natural gas produced from new leases as well as natural gas produced from interests in old leases acquired before the effective date of the statement of policy. The Commission is also considering the possibility of excluding all natural gas produced from old leases from the definition. The Commission invites comment upon an appropriate definition of "eligible OCS natural gas."

The definition of "covered transportation" excludes natural gas which does not enter the general system supply of an eligible recipient. Hence, Subpart H does not apply to the transportation of natural gas which is produced by an eligible joint venture for delivery to participants who are not eligible recipients.

The § 284.1(a) definition of "transportation" which includes backhaul, displacement and exchange will apply to the program instituted by their regulations.

Section 284.243

Paragraph (a) states the general rule governing which transportation arrangements will be authorized pursuant to this subpart. Transactions which do not meet these criteria are governed by § 284.247. As is the case in the Commission's direct sale program for essential agricultural and other high-priority users (Order No. 27), either an interstate pipeline or the eligible recipient applying on the pipeline's behalf may file the application with the Commission.

Paragraph (b) makes clear that the applicant may elect to file for authorization under either section 311(a) of the NGPA or section 7(c) of the Natural Gas Act. However, the abandonment jurisdiction of section 7(b) of the Natural Gas Act applies to any section 7(c) certificate. As a result, an applicant for authorization under section 7(c) may wish to seek a pregrant of abandonment as part of the application.

Section 284.244

This section prescribes filing requirements in addition to those applicable under Subparts A and B of this part or Part 157.

Section 284.245

This section specifies the terms and conditions which apply to covered transportation. Additional terms and conditions may be included in the order authorizing the transactions. In addition, the Commission would waive its right to prospectively impose further terms and conditions (see § 284.5) when appropriate.

Proposed paragraph (a) incorporates the terms and conditions of Subparts A and B of this Part for transactions authorized under either section 311(a) of the NGPA or section 7(c) of the Natural Gas Act.

Proposed paragraph (b) requires the OCS gas to be allocated according to the curtailment plan which governs the general system supply of the eligible recipient. This requirement reflects a concern expressed in the legislative history of section 603:

> [T]he intent of this section is to benefit local distribution companies only. It is designed to facilitate entry by such companies in the Outer Continental Shelf leasing so that they can distribute the proposed natural gas to their service areas only.[9]

[9] S. Report No. 95-1091, 95th Cong. 2d Sess. (1978) at 158.

If the local distribution company were allowed to assign the OCS gas to a specific end-user instead of incorporating the OCS gas into its system supply, this objective would not be met.

Section 284.248

The proposed rule does not disqualify interstate pipelines from transporting OCS gas on behalf of a local distribution company which is not an eligible recipient, under Subpart B of Part 284. The Commission will consider such transactions on a case-by-case basis. However, the policies proposed here do not apply to such transactions.

III. Environmental Considerations

The Commission finds that the issuance of a statement of policy, as proposed here, would not significantly affect the quality of the human environment.[10] The proposed rule is basically clarifying in nature and does not substantially change the effect of existing regulations.

IV. Written Comment Procedures

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. An original and fourteen (14) copies should be filed with the Secretary of the Commission. All comments received prior to December 10, 1979, will be considered by the Commission before promulgation of final regulations. All written submission will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E, Washington, D.C., 20426, and should reference Docket No. RM80–11.

V. Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on December 3, 1979, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., December 3, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM80–11 and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five (5) copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m. on December 7, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring twenty (20) copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel, whose members will be designated by the Chairman of the Commission may question such persons. In addition, any interested persons may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether a question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be anounced by the presiding officer at the

[10] We note that the Council on Environmental Quality has issued regulations implementing the National Environmental Policy Act (40 CFR 1501.4(a), 1508.4) which provide for identifying categories of actions which normally do not produce significant environmental effects and which therefore can be excluded from agency NEPA review. (See Notice of Proposed Rulemaking issued in Docket No. RM79–69 on August 20, 1979, 44 Fed. Reg. 50052 (August 27, 1979)).

hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. § 3301, *et seq.*; Outer Continental Shelf Lands Act Amendments of 1978, Pub. L. 95-372, 43 U.S.C. § 1801, *et seq.*)

In consideration of the foregoing, Parts 280 and 284 of Subchapter I, Chapter I of Title 18, Code of Federal Regulations, are proposed to be amended as follows.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 280.101 is amended by adding a new subparagraph (2) in paragraph (b) to read as follows:

§ 280.101 Definitions

* * * * *

(b) *Other definitions.* For the purpose of this subchapter:

* * * * *

(2) "OCS" means the Outer Continental Shelf as defined in section 2(35) of the NGPA.

2. The table of contents for Part 284 is amended by the addition of a new Subpart H, to consist of sections 284.241 through 284.247:

Subpart H—Transportation of Natural Gas From the Outer Continental Shelf on Behalf of Local Distribution Companies

Sec.

284.241 Applicability.
284.242 Definitions.
284.243 General rule, criteria.
284.244 Application requirements.
284.245 Terms and conditions.
284.246 Other transportation of OCS natural gas.

3. Part 284 is amended by the addition of new subpart H to read as follows:

Subpart H—Transportation of Natural Gas From the Outer Continental Shelf on Behalf of Local Distribution Companies

§ 284.241 Applicability.

This subpart implements section 603 of the Outer Continental Shelf Lands Act Amendments of 1978 and applies to transportation of natural gas from certain OCS leases to a local distribution company for its general system supply.

§ 284.242 Definitions.

For the purposes of this subpart:

(a) "Producing affiliate" means any person which is:

(1) Exploring for, developing, or producing natural gas on the OCS;

(2) Controlled by a local distribution company; and

(3) Regulated, or operated as a public utility, by a state or local government or agency thereof.

(b) "Eligible joint venture" means an association formed for the purposes of purchasing, exploring, and developing an OCS lease in which an eligible recipient participates.

(c) An "eligible recipient" is a person engaged in the distribution of natural gas at retail and regulated, or operated as a public utility, by a state or local government or agency thereof.

(d) "Eligible OCS natural gas" means natural gas produced from the OCS pursuant to:

(1) A lease entered into on or after April 20, 1977, or

(2) An interest which was acquired before [effective date of rule,] in a lease which was entered into prior to April 20, 1977.

(e) "Eligible OCS producer" means:

(1) A producing affiliate of a local distribution company;

(2) An eligible recipient; or

(3) An eligible joint venture.

(f) "Covered transportation" means the transportation by an interstate pipeline of eligible OCS natural gas from an eligible OCS producer to an eligible recipient.

§ 284.243 General rule.

(a) *Applications.* Any interstate pipeline, or eligible recipient on behalf of an interstate pipeline, may file applications for covered transportation. The Commission will consider such applications on a priority basis if the following criteria are met:

(1) Eligible OCS natural gas is produced on a lease owned in whole or in part by an eligible recipient; and

(2) The eligible recipient will use all of the transported natural gas for its general system supply.

(b) *Election by applicant.* Covered transportation may be authorized under either section 311 of the NGPA or section 7(c) of the Natural Gas Act. The applicant shall elect the form of authorization at the time of filing an application. In either case, the covered transportation shall be subject to the terms and conditions of § 284.245.

§ 284.244 Application requirements.

An application for covered transportation shall include, in addition to the requirements of Part 157 of this chapter that implement section 7(c) of the Natural Gas Act or Subparts A and B of this part that implement section 311(a) of the NGPA, as appropriate, the following:

(a) A description of the lease under which the eligible OCS producer is exploring the OCS;

(b) A copy of the joint venture agreement, if any, to which the eligible OCS producer is a party;

(c) A copy of the contract(s) applicable to the transportation of the eligible OCS natural gas; and

(d) A copy of a document verifying that the eligible recipient is regulated as a public utility by a state or local authority.

§ 284.245 Terms and conditions.

(a) *General.* Covered transportation authorized under either section 7(c) of the Natural Gas Act or under section 311(a) of the NGPA shall be subject to the terms and conditions, rates and charges, and reporting requirements of Subparts A and B or this part (as amended from time to time).

(b) *Curtailment.* Natural gas transported pursuant to this subpart shall be subject to the terms of any currently effective curtailment plan which governs the allocation of natural gas from the general system supply of the eligible recipient.

§ 284.246 Other transportation of OCS natural gas.

A transportation arrangement involving natural gas produced from the OCS which does not comport with the criteria of this subpart may be:

(a) authorized on a self-implementing basis under Subpart B of this part; or

(b) considered on a case-by-case basis by the Commission for authorization under this subpart.

¶ 32,048 Rule Required Under Section 202 of the Natural Gas Policy Act of 1978

44 F. R. 67170 (November 23, 1979).

18 CFR Part 282

[Docket No. RM80-10]

Rule Required Under Section 202 of the Natural Gas Policy Act of 1978; Proposed Rulemaking and Public Hearings

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking and Public Hearings.

SUMMARY: The Federal Energy Regulatory Commission hereby proposes regulations to implement section 202 of the Natural Gas Policy Act of 1978. Under the proposal, the incremental pricing program would be expanded on November 1, 1980, to include all industrial users of natural gas that are not granted an exemption from the program by statute. The final regulations to be adopted pursuant to this proposal will be subject to review by the Congress prior to their taking effect.

DATES: Comments: By January 31, 1980. Hearing dates: To be announced.

ADDRESSES: All comments to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C., 20426 (Reference Docket No. RM80-10). Hearing locations: to be announced.

FOR FURTHER INFORMATION CONTACT: Walter W. Schroeder, Executive Assistant to the Chairman, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8335.

Nancy E. Williams, Deputy Assistant General Counsel for Regulatory Development, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8033.

November 15, 1979.

I. Introduction.

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that the Federal Energy Regulatory Commission (the Commission) promulgate regulations to channel a specified portion of the acquisition costs of natural gas to industrial users. The "incremental costs" of natural gas are to be passed through from the supplier to the industrial facility by means of a surcharge pricing mechanism.

Title II further requires that the incremental pricing program be inplemented in two phases. The first phase has been implemented by regulations that were issued by the Commission on September 28, 1979 (44 FR 57726, October 5, 1979). The regulations issued on September 28 were contained in two dockets, Docket Nos. RM79-14 and RM79-21. Under those regulations only large industrial facilities which use natural gas as a boiler fuel are subject to incremental pricing.

Section 202 of Title II requires the Commission to promulgate a second phase (Phase II) rule by May 9, 1980, which may extend the incremental pricing program to other (non-boiler) industrial users. This rule will be subject to Congressional review pursuant to the provisions of the NGPA. If either House votes to disapprove it, the rule promulgated by the Commission will not take effect.

For the reasons set forth below, the Commission has decided to propose a Phase II rule that would broaden the scope of incremental pricing to include all industrial users other than those specifically exempted by Title II. Further, the Commission proposes that the Phase II rule incorporate the same three-tier alternative fuel ceiling approach adopted in the Phase I regulations. The Commission also proposes that the Phase II regulations retain the mechanism for calculating

and billing incremental pricing surcharges, commonly referred to as the "reduced PGA" approach, that was developed and finalized under the Phase I program. Finally, the Commission proposes that the "adjustments" procedure available pursuant to the mandate of section 502(c) of the NGPA serve as the primary means for the Commission to address individual situations involving special hardship or inequity under the generally applicable Phase II regulations.

II. The Statutory Mandate to the Commission.

Title II of the NGPA and the accompanying Statement of Managers provide a clear directive to the Commission to propose a broad expansion of incremental pricing in its second phase rule. Section 202, which mandates the second phase rule, is entitled "Amendment Expanding Application for Other Industrial Uses." Subsection (b) of section 202 provides that the second phase rule:

> "*shall apply* with respect *to* the *industrial use of natural gas* (as defined by the Commission in such rule), including boiler fuel use of natural gas * * * *by*—
> (1) *any* industrial *boiler fuel facility* (as defined in section 201(c)(1)); *and*
> (2) *any industrial facility* which is within a category defined by the Commission in such amendment as subject thereunder to the requirements of such rule which is not exempt under Section 206. (emphasis added)

The Statement of Managers of the NGPA further evidences a Congressional intent that the incremental pricing program be expanded from a program of relatively narrow scope in Phase I to a much broader scope in Phase II. The statement provides:

> The conference agreement requires the Commission to prescribe a rule for implementing incremental pricing. Each pipeline would be required under the rule to place certain portions of its acquisition costs of natural gas into a special incremental pricing account for passthrough to incrementally priced users.
>
> A two stage process is utilized for identification of users who will be subject to incremental pricing. First, the Commission is required to develop a rule, within 12 months after the date of enactment, for implementation of incremental pricing applicable to certain industrial boiler fuel facilities. Second, the Commission is required to develop an amendment to the first rule, within 18 months after the date of enactment, for implementation of incremental pricing to other industrial users.[1]

These directives, and the additional considerations discussed below, lead the Commission to propose that the rule required by section 202 of Title II broaden the scope of the incremental pricing program to include all industrial users. The rule would not, of course, apply to facilities exempted from the program by statute. Moreover, the Commission proposes to exempt all "small" industrial users in much the same manner as small boiler fuel users are already exempt.

In sum, Title II of the NGPA requires that this Commission develop a program to extend the Phase I, boiler-fuel incremental pricing program to all industrial users of natural gas and submit this program to Congress for its review. Section 202 of the NGPA vests the Commission with the authority to include within the incremental pricing program any category of industrial facility that the Commission determines would be appropriate to include. The Commission believes that the Congressional purposes underlying incremental pricing would be most fully met if all industrial users, other than those specifically excluded by statute, are brought within the scope of Title II.

The Commission further believes that the most practicable means of dealing with potential hardships or inequities resulting from incremental pricing is on a case-by-case review pursuant to section 502(c), rather than in a generic proceeding.

The remaining sections outline the basic features of the Phase II rule that the Commission proposes to submit to Congress.

[1] House Report No. 95-1752, Octoberr 10, 1978, pages 94, 95.

III. Proposal With Respect to the Scope of Phase II.

The proposed definition of industrial facility utilized in Phase II would be the same as that which is incorporated in the Phase I regulations issued on September 28, i.e.:

"Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

Some respondents to the Commission's Notice of Inquiry in RM79–56 (discussed infra in section IX), point out that some facilities within the scope of the broadest possible expansion of incremental pricing may not have the capability to use fuel oil as an alternative to natural gas. These observers generally argued that industrial facilities without fuel oil capability should not be made subject to incremental pricing. The Commission is currently of the view that the absence of alternative fuel oil capability should not prevent the application of incremental pricing to that facility. Explication of the basis of this view requires some discussion of the history of Title II.

During the legislative debate that eventually produced the NGPA, various Congressional spokesmen argued that deregulated new gas prices would initially be driven far above long-run market clearing levels. Congress took the position that such an occurrence would produce an unjust and unacceptably large income transfer from consumers to producers. The House Ad Hoc Committee on Energy, in its report accompanying H.R. 8444, stated that upon sudden deregulation

an interstate pipeline will be able to bid extremely high prices for new supplies of natural gas, which even deregulation proponents concede will be relatively small as compared to the volumes of presently flowing natural gas. The interstate pipelines, unlike the intrastate pipelines, are not constrained by a limited demand for natural gas. Using rolled-in pricing, interstate pipelines can bid the price of new supplies of natural gas to unprecedented levels of $5 per Mcf or more. (page 395)

This Congressional concern over the disruptive effect of deregulation were it to occur during a period of market imbalance is also illustrated by an economic analysis of the NGPA that accompanied its final adoption by the House.[2] This analysis estimated that the deregulation bill that had previously been passed by the Senate would have resulted

in new gas prices rising very quickly, to $4.73 per Mcf in 1980 and then dropping slowly during the next several years to a price of $4.48 per Mcf in 1985, after which prices would escalate with the general inflation rate. Prices are highest when unregulated gas represents only a small fraction of pipeline supplies. They drop to equivalence with substitute fuels as the percentage of unregulated pipeline supply increases. This projected disorderly price path under sudden deregulation is the main reason why the conference committee ultimately adopted a mechanism consisting of intrastate controls and moderate price escalation to prepare the natural gas system for eventual decontrol.[3]

The Congress perceived a supply/demand imbalance for natural gas in 1977 and 1978. The NGPA was enacted as a transition mechanism to orderly deregulation in 1985. But concern remained that markets would not be ready for deregulation by then. Congress' solution to the potential problem of excess demand for natural gas relative to its supply in 1985 was to increase the delivered price to large industrial users in order to eliminate industrial demand arising from the artificial "subsidy" effect of rolled-in pricing.[3]

In short, Congress in enacting Title II sought to raise the price of natural gas to

[2] *Economic Analysis of H.R. 5289, Natural Gas Policy Act of 1978*, Prepared by the Staff of the Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, October 13, 1978, pp. 4–5.

[3] See House Committee Print 95–31, *Economic Analysis of Natural Gas Policy Alternatives*, Committee on Interstate and Foreign Commerce, Subcommittee on Energy and Power, December 1977, pages 11 and 12. Rolled in pricing refers to the phenomenon in which a pipeline can blend high-priced gas with lower-priced regulated gas and still keep the average price of gas within marketable limits.

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large industrial customers to a level at which further increases would threaten to cause loss of industrial load, and thereby reduce total sales of interstate pipelines. Incremental pricing was thus intended to place the large industrial users in the role of motivating their pipelines to refrain from bidding up the price of deregulated natural gas or relying excessively on the regulated gas categories with high ceiling prices. Achieving this objective of Title II would appear to require maximizing the number of industrial users included within the program. A user's lack of alternative fuel oil capability does not dispose of the question of whether his consumption is price sensitive. Higher natural gas prices to process or feedstock users should encourage conservation and other actions (such as adding alternative fuel capability) affecting the use of natural gas. The Congressional purpose of achieving market balance by 1985 may require the full exploitation of economic incentives for demand reduction.

The proposed expanded scope of Phase II also arises from the possibility that by 1985 declining total natural gas production and the operation of curtailment plans will prevent incremental pricing from accomplishing demand restraint. Phase I users are among the lowest priority users of natural gas; if heavily curtailed, Phase I users would no longer be in a position to affect their pipelines' bidding decisions. Under such circumstances, demand restraint could be achieved only through measures applicable to users of higher priority than industrial boilers.

Accordingly one of the areas that the Commission must examine in promulgating a Phase II rule is the demand and supply outlook for natural gas markets as deregulation in 1985 approaches. The ultimate status of gas markets in 1985 turns on future volumes and prices of natural gas that the Commission is not presently able to ascertain with the clarity necessary to make a definitive determination that the scope of Phase II should be any less broad than authorized by Title II.

Commenters that have made pertinent analyses are specifically requested to provide the Commission with estimates of natural gas demand and supply in 1985 and 1990 on either a pipeline system, state, or nationwide basis. In addition, the Commission seeks projections of delivered natural gas prices as of year-end 1984 to each major user category under the assumption that no Phase II rule becomes effective and how such prices would compare with the projected price of alternative fuels to each user category. Projections and analyses of these types will assist the Commission in evaluating the impacts of the Phase II proposal described herein, and other possible alternatives.

A second purpose of incremental pricing is to shelter residential and other high priority natural gas consumers from the full near-term impact of wellhead price increases permitted by the NGPA. This effort to mitigate price impacts on non-industrial customers is accomplished by recovering a greater proportion of interstate pipeline purchased gas costs for users subject to incremental pricing than from other users. Through the interaction of incremental pricing surcharge accounts (recovered only from incrementally priced users) and normal purchased gas adjustment accounts (recovered from all users), non-incrementally priced users will receive the greatest rate benefits when the recovery of gas costs from incrementally priced users is maximized. The Commission is highly cognizant of its mandate to afford high priority users the full measure of price protection consistent with the purposes of Title II, and believes that this protection will be best achieved by maximizing the volume of natural gas use subject to incremental pricing.

As discussed extensively in the final orders issued in Docket No. RM79-21, the Commission must balance two competing objectives found in Title II of the NGPA. The first objective is to maximize the recovery of NGPA-related wellhead price increases from industrial customers.

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The second objective is to set the alternative fuel cost ceilings on incremental pricing surcharges at a level that will not encourage industrial users to swtich from natural gas to fuel oil if such switching would result in increased rates for residential and small commercial customers. The Commission believes that these balancing considerations remain critical to proper implementation of the incremental pricing program as broadened by Phase II. The need to insure that consumers are not damaged by virtue of having to pay more of the fixed costs of the natural gas transmission and distribution system does not mean that no loss of industrial load is permissible. Some load loss may be compatible with Title II if, among other reasons, the resulting reduction in deregulated gas prices more than offsets the increased allocation of fixed costs to high priority customers. Such a result could occur if the reduced industrial demand for gas so reduces bidding pressures on deregulated gas that the average unit cost of gas acquisition (at the wellhead) is decreased by more than the amount by which the average unit cost of transmission and distribution is increased.

Comments on the Commission's responsibility to minimize the delivered cost of gas to high priority customers, the relationship of the objective to the issue of load loss, and the implications from Phase II implementation are requested.

IV. Proposal With Respect to the Level of Incremental Pricing.

An issue central to the expansion of incremental pricing is the level of ceiling prices that should be applied to non-boiler fuel facilities. One possibility would be to use the same ceilings as in Phase I. Another would be to develop some other ceilings for non-boiler fuel use of gas. Stated alternatively, the question is whether industrial facilities which utilize natural gas for a process or feedstock use (including those with no alternative fuel capability) should pay prices equivalent to the No. 2 or No. 6 fuel oil prices, as adjusted pursuant to Order No. 50.

If industrial non-boiler fuel natural gas were to be incrementally priced in some manner different from the way boiler fuel users are treated, the question becomes what ceiling level(s) would be appropriate. Should such users be subject to the highest ceiling prices under Title II, on the theory that these users should absorb as much as they are able to bear inasmuch as there is no reasonable prospect of load attrition and, therefore, no potential adverse impact on high-priority customers due to load loss? Or, on the other hand, would it be appropriate to price these users at low ceiling prices on the theory that natural gas use by these facilities is so insensitive to price that to impose the highest statutory price would be punitive?

The Commission proposes at this time that the three-tier ceiling adopted for purposes of Phase I be used for Phase II as well. The Commission believes that the advantages of the three-tier approach are equally as applicable to Phase II as they are to Phase I. Adoption of the three-tier approach would encompass the presumption that a user who did not have No. 5 or No. 6 alternative capability would be deemed to have No. 2 fuel oil capability. This aspect of the three-tier approach is described in more detail below. However, the Commission recognizes that the questions set out above pose difficult policy issues and seeks guidance with respect to the preferred resolution of this matter. Users whose only alternative fuel is propane are asked to suggest possible approaches for alternative fuel cost treatment within the limits prescribed by section 204 of the NGPA.

Under the final regulations adopted by the Commission in Order No. 50, non-exempt industrial boiler fuel facilities will be priced for their use of natural gas up to the price equivalence of No. 2 fuel oil unless they can demonstrate a capability to use less costly No. 5 or No. 6 fuel oil. The principal advantage of the three-tier ceiling approach is that it

should cause the ceiling applicable to any particular incrementally priced facility to be high enough to maximize the recovery of incremental costs from that facility, yet low enough to minimize the likelihood that the facility would switch to an alternative fuel. Where lower cost fuel oil capability exists, users will be subject to lower natural gas ceiling prices corresponding to the price equivalence of either low sulfur or high sulfur No. 6 fuel oil. The principal advantage of this three-tier ceiling approach is that it should cause the ceiling applicable to any particular incrementally priced facility to be high enough to maximize the recovery of incremental costs from that facility, yet low enough to minimize the likelihood that the facility would switch to an alternative fuel. The three-tier system would seem to offer the potential to achieve the maximum possible flow-through of incremental costs to industrial customers without causing load loss. An additional advantage of the three-tier approach is that is imposes minimal administrative burdens on users subject to incremental pricing.

While adopting the three-tier approach as a permanent part of incremental pricing, the Commission adopted an interim rule under which facilities subject to incremental pricing will be priced only up to the equivalent price of No. 6 high sulfur fuel oil (the lowest priced of the three tiers) for ten months. This interim rule to exempt users from the upper two tiers contained in the permanent rule was adopted by the Commission as an exemption under the authority of section 206 of the NGPA and had to be submitted for Congressional review before it could become effective. The interim exemption rule was not disapproved by the Congress, and thus the single high-sulfur No. 6 tier will apply for the first ten months of the program, from January 1, 1980 through October 31, 1980.

Increased cost absorption by industrial users under the three-tier rule should have the effect of reducing the impact of rising wellhead gas prices on residential and other high priority customers to as full an extent as is possible given the constraint that Phase I is limited to boiler fuel users. The record in the proceeding on the three-tier rule indicated that the maximum surcharge absorption capability of industrial boiler fuel users will probably be less than the amount of purchased gas costs subject to incremental pricing as soon as the rule takes effect. If industrial boiler fuel users subject to Phase I are in fact likely to be pushed immediately to alternative fuel ceiling prices, it works to the disadvantage of high priority users to permit only the lowest of the three tiers to operate any longer than necessary. Hence, the Commission adopted the single tier rule for only a ten-month interim period.

By increasing the amount of industrial use subject to incremental pricing, the proposed Phase II rule should increase the total surcharge absorption capability of industrial users. If, initially, the effect of the Phase II rule would be to cause the aggregate surcharge absorption capability of incrementally priced users to exceed the amount of purchased gas costs subject to incremental pricing, then there would be no adverse consequence on high priority users if the single tier rule, or some other exemption falling short of the three-tier rule, were to remain in effect beyond October 31, 1980. Accordingly, the Commission seeks as detailed information as is available on the amount by which the proposed Phase II rule would increase maximum surcharge absorption capabilities under alternative ceiling approaches.

To best assist the Commission, commenters are asked to provide any available data regarding the following questions:

1. Under Phase I, what is the estimated 1980 average maximum surcharge absorption capability (MSAC) under the single No. 6 ceiling? What would the Phase I MSAC be if the three-tier rule were in effect?

2. What is the current delivered price of natural gas to non-boiler industrial

users served directly or indirectly by interstate pipelines?

3. What is the current price of alternative fuels for these users?

4. On the basis of current or estimated 1980 volumes consumed by these industrial non-boiler users, what increase in the MSAC would occur under the proposed Phase II program relative to Phase I? Both dollar amounts and percentages are desired.

Ideally, analyses will utilize alternative assumptions relating to the ceiling price applicable to industrial users without fuel oil capability. One computation should assume users are priced at the No. 2 fuel oil level. The other computation should assume that users without alternative fuel oil capability are priced at the high sulfur No. 6 fuel oil price. For both computations, assume that the three-tier approach applies to all users with fuel oil capability.

Analysts should identify whether data apply to a pipeline system, distribution company, state, or nationwide.

V. Proposal With Respect to Surcharge Computation and Passthrough Mechanism for Phase II

As stated previously, the Commission adopted a mechanism for implementation of the Phase I program which is commonly referred to as the "reduced PGA" method. This mechanism requires that pipelines estimate, for several months into the future, their natural gas acquisition costs and the amount of such costs subject to being passed through to industrial users as incremental pricing surcharges. The pipeline supplier then recovers his purchased gas costs through both incremental pricing surcharges and the purchased gas costs adjustment (PGA) rate. The amount which would otherwise be reflected in the PGA rate is reduced by the amount estimated to be recovered through incremental pricing surcharges in order to avoid double recovery. The primary reason the Commission determined to adopt this approach was that it results in an almost immediate flow through of the benefits of the incremental pricing program to high priority customers.

The Commission has concluded that the regulations which provide the structure for the Phase I incremental pricing program should generally be retained and utilized for Phase II. The Commission does, however, request specific comment on the adaptability of the Phase I regulations to Phase II as it is proposed herein. In particular, the Commission requests comment on whether the "reduced PGA" mechanism will be adaptable to the Phase II program.

Several commenters indicated in their comments submitted in Docket No. RM79-14 that they believe the "reduced PGA" mechanism would not be workable if the class of affected end-users were significantly expanded. The "reduced PGA" method entials numerous estimates, calculations, and a large reporting network in order to operate smoothly. Commenters indicated that each step could not be completed in a timely fashion if end-users subject to incremental pricing surcharges were to increase in number.

Commenters who held this view are requested to explain in detail why they conclude that the "reduced PGA" approach would not be workable for Phase II. The Commission is interested in estimates of the number of additional end-users who would become subject to incremental pricing under Phase II, and who are not already subject to Phase I. Measures of the work-load and computational time implications of the proposed Phase II rule are also requested.

In addition, the Commission seeks estimates of the anticipated level of purchased gas costs subject to incremental pricing in 1980 and in 1985. Based on this information and the calculations of maximum surcharge absorption capabilities requested in the previous section, parties are requested to provide information as to whether under Phase II the aggregate absorption capability of a pipeline's customers will exceed the total incremental gas costs which may be passed through to such

users. If so, how long will it take for the incrementally priced industrial users served by the pipeline to reach their alternative fuel ceilings?

Commenters who believe that the "reduced PGA" method will not be workable for Phase II, are requested to described in detail alternative methodologies that the Commission should consider. In this regard, the Commission continues to adhere to its position, adopted in the Docket No. RM79–14 proceeding, that the mechanisms for calculation and billing of incremental pricing surcharges should result in as little delay as possible in the recovery of incurred acquisition costs.

One other aspect of the Phase I mechanism merits mention at this point. The Phase I regulations currently require installation of submeters within industrial facilities to determine the volume of gas used for non-exempt purposes. This requirement will become effective November 1, 1980. In the interim ten-month period, the Commission will rely on certified estimates. Expansion of the program to all industrial uses of natural gas might eliminate the need for many submeters which would otherwise have to be installed, and would in part resolve the difficult issue of submetering.

However, submetering might still be required in order to differentiate between the volumes of gas used for boiler fuel and for other uses, should the Commission determine that different ceilings should apply to the different types of use. An additional need for submeters may arise in conjunction with providing exemptions to "small" users, as described in the following section.

Commenters are invited to address the question of the degree of submetering which would be necessary under the Phase II program as proposed here.

VI. Proposal With Respect to "Small" Nonboiler Fuel Industrial Facilities.

The Commission's current intention is that the proposal to expand incremental pricing to all industrial facilities would not encompass "small" industrial facilities. This exemption would be consistent with the statutory exemption granted to "small" boiler fuel facilities. For purposes of Phase I, a small boiler fuel user is defined as any boiler facility using 300 Mcf or less per day. For purposes of Phase II, this 300 Mcf threshold will be adjusted to the level required to make 95 percent of total industrial natural gas boiler fuel transported by interstate pipelines subject to incremental pricing (5 percent rule).

The statute requires that the eligibility for the "small" boiler fuel facility exemption be based on the volume of natural gas consumed in 1977. If the volume used in 1977 was below the threshold, the facility qualifies for the exemption.

The base period approach for identifying "small" boiler fuel facilities has certain disadvantages. For example, the approach does not account for situations where the base period use was anomalous. Nor does the approach provide for the treatment of facilities constructed since the base period. Finally, the approach leaves open the question of the treatment of facilities whose usage has been altered since the base period.

Because of such problems, the Commission has determined that the exemptions for "small" non-boiler fuel facilities should be based on the current use of natural gas in the facility.

To implement this approach, the Commission proposes to look to a base period comprised of the six months prior to the effective date of the Phase II regulations. In this regard, the Commission proposes to make the Phase II regulations effective on November 1, 1980.

If in any billing month beginning after April 30, 1980, the facility used more than an average of 300 Mcf per day (or the permanent threshold in accord with section 206(a)(2) of the NGPA, if lower) for a non-boiler fuel use, the facility would be subject to incremental pricing as to all such use under Phase II. Further, any facility constructed following the effective date of the Phase

II rules would become subject to the program when and if its usage exceeds the threshold volumetric limit.

Finally, the Commission currently believes that the "small" boiler fuel facility exemption and the exemption described above for other uses of natural gas should be additive. Thus, any one facility could receive a "small" exemption with respect to either or both its boiler fuel use and its other uses of natural gas so long as both uses are below their threshold levels.

The additive rule is perhaps best explained by way of example. A facility consumed 250 Mcf per day (peak month) of boiler fuel in 1977. It currently consumes an additional 250 Mcf per day for process use. Assuming that the small exemption threshold is not reduced by the 5 percent rule but remains at 300 Mcf per day, the entirety of the facility's use would be exempt from incremental pricing because each type of use is below its volumetric threshold. On the other hand, a facility that consumed 350 Mcf per day (peak month) of boiler fuel in 1977 and which consumes 150 Mcf per day for process use would be incrementally priced for the totality of its boiler fuel use. This latter facility, even though it uses the same total volume of gas as the former, would be exempt only with respect to its non-boiler fuel use (and only for so long as this non-boiler fuel use remains below 300 Mcf per day).

The Commission has considered but tenatively rejected alternative approaches to exemptions for small industrial users. One alternative would be to simply exempt any facility whose combined use of natural gas for boiler and non-boiler fuel is less than 600 Mcf per day. This option has been rejected because it would permit large boiler fuel users (greater than 300 Mcf per day) to benefit from an exemption so long as process use is sufficiently small to keep total consumption below 600 Mcf per day. Such a result is plainly inconsistent with the language and intent in section 206(a) that the boiler fuel exemption apply only to facilities using 300 Mcf per day or less.

Another alternative to small industrial user exemptions would be the "single threshold" approach. Under this approach the single 300 Mcf per day threshold would apply to the entirety of a facility's consumption. The advantage of this approach is its simplicity. However, one problem is that it may also bring about inequities. If total consumption were to exceed the 300 Mcf per day threshold, only the volume below the threshold would be eligible for an exemption, and any use in excess of the threshold would be subject to incremental surcharges. This treatment could result in a small volume of natural gas used as non-boiler fuel, when used in conjunction with boiler fuel use, being incrementally priced, while a user which consumed a substantially larger amount (up to the threshold amount) of gas for non-boiler fuel purposes might receive an exemption for his entire non-boiler consumption.

For example, if one facility used 290 Mcf per day (peak month) for boiler fuel in 1977 and currently consumes 50 Mcf for process use, the 50 Mcf non-boiler fuel use would be subject to incremental pricing under the "single threshold" approach. The facility's boiler fuel use would be exempt because it it is covered by the small boiler exemption. A second facility using no boiler fuel but using 290 Mcf per day for process use would be totally exempt because its consumption would be less than the "single threshold." The anomolous result is that the smaller process fuel use is incrementally priced, while on the other hand the larger use is exempt.

However, the Commission remains concerned that the additive approach may result in granting an exemption to a facility consuming up to 600 Mcf per day (or twice the threshold established for Phase II) and that such a facility is not sufficiently "small" to warrant special treatment. Thus, comments are requested on the question of whether the "small" exemptions should be treated as proposed above, or whether some alternative approach should be adopted in order to achieve

administrative simplicity and equitable impact.

VII. Proposal With Respect to Adjustments to Phase II Regulations.

Section 502(c) of the NGPA vests in the Commission the authority to grant "adjustments" to any regulations adopted under the statute in order to alleviate special hardship, inequity, or an unfair distribution of burdens. The Commission has adopted procedures under which an application for such an adjustment may be filed for consideration by the Commission (18 CFR 1.41). Decisions on adjustment applications are issued by the Office of Pipeline and Producer Regulation, and may be appealed to the Commission for review.

When regulations are adopted to implement the Phase II program, 502(c) adjustments will be available with respect to those regulations, as they are now with respect to other NGPA regulations. One category of "adjustments" which are to be made available under section 502(c) are "exemptions." Section 206(d) also provides for "exemptions" from regulations which implement Title II of the NGPA, and makes such exemptions subject to Congressional review before they may take effect.

The Commission is concerned that an argument could be made that the provisions of section 206(d) indicate that all "exemptions" granted to regulations which implement Title II must be subject to Congressional review. The Commission believes that section 206(d) does not impair its authority under section 502(c) and that section 206(d) is applicable only to actions which would grant generic exemptions from the mandatory provisions of the statute. The Commission views the section 502(c) "exemptions" as actions which would grant an exemption from regulations which were adopted pursuant to the Commission's discretion.

In order to obviate a possible challenge on this point, however, the Commission has determined to propose to include provisions in the Phase II regulations which would provide for the granting of 502(c) exemptions by the Commission. The Commission believes that Congressional review of the totality of the Phase II regulations (including the proposed 502(c) "exemption" procedures) would constitute Congressional approval (or disapproval) of the Commission's authority to grant 502(c) "exemptions". Comments are requested on this proposal.

The Commission also solicits comment on the criteria it should utilize in order to reach determinations on all—exception, exemption, modification and rescission—502(c) adjustment applications.

The Commission has made a preliminary determination that it is premature at this time to attempt to further define the statutory criteria of "special hardship, inequity, or unfair distribution of burdens". The Commission believes further refinement should not be undertaken until the Commission has gained experience in reviewing 502(c) applications and is more familiar with the reasons why such relief would be appropriate. However, the Commission solicits comments on this point at this time.

VIII. Proposal With Respect to Permanent Exemptions for Small Boilers and Agricultural Uses.

As discussed in the preamble to the final rule in Docket No. RM79–14, section 206(c) of the NGPA requires that permanent exemptions with regard to small boilers and agricultural uses be promulgated prior to May 9, 1980. (The interim exemptions for these two categories were required to be adopted by November 9, 1979, and were incorporated in the regulations issued on September 28, 1979.)

The two permanent exemptions are not, however, unlike the rule required by section 202, subject to Congressional review. The Commission currently plans to adopt regulations with respect to the two permanent exemptions on a time schedule similar to the one for the rule required by section 202, but to open separate dockets for each. This will aid in keeping comments focused on the

issues important to each of the three dockets. This approach will also allow us to have the regulations on the permanent exemptions in place, should the Congress ultimately disapprove the regulations promulgated in this docket.

IX. Interface of Incremental Pricing Program with Curtailment Program.

On June 28, 1979, (44 FR 38857, July 3, 1979), the Commission issued a Notice of Inquiry (RM 79–56) with respect to a study proposal to link incremental pricing with curtailment policies. The basic feature of the study proposal is to allow each industrial user subject to incremental pricing (under both Phase I and Phase II) to determine its own alternative fuel value. This alternative fuel value would then determine each user's curtailment status. Users choosing a low alternative fuel ceiling for incremental pricing purposes would obtain relatively lower-priced gas, but would also receive correspondingly low priority status, so that they would be curtailed prior to users choosing higher priced alternative fuel ceilings.

In issuing the study proposal for public comment, the Commission indicated that it:

> * * * is interested in this proposal for a number of reasons. First, it is an intriguing approach to curtailment policy because it appears to address many of the problems that the courts have expressed with respect to current end use curtailment policy. Second, the proposal is viewed by some Commission staff as a means of lessening perceived administrative and economic burdens associated with incremental pricing. Finally, the proposal seeks to use market forces rather than regulations to create a stable and fair system for allocating supplies and costs of natural gas. (mimeo p. 2; 44 FR 38858)

An informal conference on the subject was held on August 7, 1979. In addition, numerous written comments were submitted in response to the Notice. The majority of commenters criticized the proposal and suggested that the concept of tying these two programs together is too sweeping to merit serious attention at this time. The Commission remains intrigued with the concepts expressed in the study proposal, but would prefer to leave the issue open for constructive development if circumstances surrounding the full implementation of incremental pricing appear to warrant increased attention to this alternative. Accordingly, the Commission does not intend to actively pursue the study proposal at this time.

X. Comment Procedures.

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C 20426 and should reference Docket No. RM80–10. An original and 14 copies should be filed. All comments received prior to 5:00 p.m. EST, January 31, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

B. *Public Hearings.* Public hearings on these proposed regulations will be held at several regional locations during the month of January, 1980. The exact dates, locations and procedures for these hearings will be announced at a later date.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, (15 U.S.C. 3301, *et seq.*).)

In consideration of the foregoing, it is proposed to amend Title 18 of the Code of Federal Regulations by revisions to Part 282, to read as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.102 is revised in paragraph (a) to read as follows:

§ 282.102 Applicability and effective date.

(a) *Uses.* (1) Natural gas used as boiler fuel in industrial boiler fuel facilities on and after January 1, 1980, shall be subject to incremental pricing under this part.

(2) On and after November 1, 1980, natural gas used in all industrial facilities shall be subject to incremental pricing under this part.

* * * * *

2. Section 282.203 is revised to read as follows:

§ 282.203 Exempt end-uses.

(a) In accordance with the provisions of sections 206 (a), (b), and (c) of the NGPA, natural gas used for the following purposes shall be exempt from incremental pricing under this part:

(1) All gas used for boiler fuel by an industrial boiler fuel facility which was:

(i) In existence on November 9, 1978; and

(ii) Did not consume more than an average of —— Mcf (to be determined in the separate rulemaking proceeding instituted to implement section 206(a)(2) of the NGPA) per day for boiler fuel during any calendar month of calendar year 1977;

(2) All gas used for an agricultural use (the definition of "agricultural use" will be determined in the separate rulemaking proceeding instituted to implement section 206(b)(2) of the NGPA);

(3) All gas used in a school, hospital, or similar institution;

(4) All gas used for the generation of electricity by an electric utility; and

(5) All gas used in a qualifying cogeneration facility.

(b) In addition, all gas used for purposes other than as boiler fuel by an industrial facility shall be exempt from incremental pricing under this part if on and after May 1, 1980, the facility does not consume more than an average —— Mcf (to be determined in the separate rulemaking proceeding instituted to implement section 206(a)(2) of the NGPA) per day for uses other than as boiler fuel during any billing month.

3. Section 282.204 is revised to read as follows:

§ 282.204 Obtaining an exemption.

(a) *General.* This section establishes procedures by which owners or operators of industrial facilities may obtain an exemption for natural gas used for the purposes described in § 282.203.

(Conforming amendments to paragraphs (b) through (f) will be made to conform the exemption affidavit procedure to the substantive provisions adopted in this and companion rulemaking proceedings.)

4. Section 282.206 is revised in paragraph (a) to read as follows:

§ 282.206 Petitions for exemptions under section 206(d).

(a) *General rule.* Any person may petition under authority of subsection 206(d) of the NGPA for the exemption, in whole or in part, of any non-exempt industrial facility or category thereof.

* * * * *

5. A new § 282.207 is added to read as follows:

§ 282.207 Exemptions under section 502(c).

(a) *General rule.* The Commission may, under authority of section 502(c) of the NGPA, exempt any non-exempt industrial facility, (or category thereof), in whole or in part, from any provision of this part.

(b) *Procedures.* The procedures set forth in § 1.41 shall apply to an application for an exemption in the nature of an adjustment as described in paragraph (a).

§§ 282.401—282.405 [Amended]

6. Sections 292.401 through 282.405 are revised by deleting "boiler fuel" wherever it appears.

§§ 282.501, 282.503 and 282.504 [Amended]

7. Sections 282.501, 282.503, and 282.504 are revised by deleting "boiler fuel" wherever it appears. (Appropriate

conforming amendments will also be made to the estimating/submetering provisions in § 282.504.)

8. Section 282.506 is revised by designating the present text as paragraph (a) and by adding a new paragraph (b), to read as follows:

§ 282.506 Refunds.

* * * * *

(b) The jurisdictional portion of any refund (including interest applicable thereto) which is attributable to service provided to non-exempt industrial facilities prior to January 1, 1981, which has not been flowed through to such users as of December 31, 1980, shall be flowed through as a lump sum payment in appropriate amounts to each appropriate natural gas supplier for the benefit of such users. Such refunds shall be calculated on the basis of sales to such users during the period when the rates which give rise to the refund were in effect.

§§ 282.602 and 282.603 [Amended]

9. Sections 282.602 and 282.603 are revised by deleting "boiler fuel" wherever it appears.

¶ 32,049 New Onshore Production Wells; Proposed Rulemaking Amending Final Regulations Implementing the Natural Gas Policy Act of 1978

44 F. R. 70189 (December 6, 1979)

18 CFR Part 271

[Docket No. PM80-12]

New, Onshore Production Wells; Proposed Rulemaking Amending Final Regulations Implementing the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission proposes to amend its final regulations implementing section 103 of the Natural Gas Policy Act of 1978 which establishes the maximum lawful price for gas from new, onshore production wells, with regard to collection of the section 103 price for gas from a second well on an existing proration unit.

DATES: Comments by January 23, 1980. Public hearing scheduled for December 17, 1979. Request to participate in the hearing must be received prior to December 12, 1979.

ADDRESSES: Send comments and request to participate to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (Reference Docket No. RM80-12). The hearing will be held at the same location.

FOR FURTHER INFORMATION CONTACT:

Thom Hirsch, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8025.
Howard Kilchrist, Director of NGPA Compliance, Office of Pipeline and Producer Rates, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8585.

November 30, 1979.

Background

Section 103 of the Natural Gas Policy Act of 1978 (NGPA) [1] established a maximum lawful price for natural gas from new, onshore production wells. These are new wells, the surface drilling of which began on or after February 19, 1977, which satisfy applicable Federal and State well spacing requirements, and which generally are not second wells on existing proration units.

In Order No. 43,[2] the Commission issued final regulations implementing section 103 of the NGPA. One of the regulations, § 271.305, established a special rule for wells drilled on existing proration units. Under § 271.305, a second well drilled on an existing proration unit may still qualify as a new, onshore production well if the jurisdictional agency finds that the second well is a new well necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well.

The Commission in Order No. 43 [3] expressed concern about the situation where the jurisdictional agency finds that both an existing well and the new well are necessary to effectively and efficiently drain the proration unit and a State agency has established an allowable or production level for the unit, but not for each well on the unit. Regarding this situation, the Commission was concerned that the special rule in § 271.305 creates an incentive to produce a disproportionate amount of gas from the new well

[1] 15 U.S.C. 3301 *et seq.* (1978).
[2] Final Rule Amending Regulations on Natural Gas From New, Onshore Production Wells * * *, Docket No. RM79-72, issued August 20, 1979, 44 FR 49651.
[3] *Id., mimeo.*, pp. 8-9.

because it commands the higher section 103 price. Consequently, the Commission established a new § 271.305(b)(2)(ii) of the final regulations, requiring the appropriate State agency in this situation to set separate allowables for each well in the unit. The allowables or production levels were to be based on the respective ability of the two wells to deliver natural gas.

After considering comments on § 271.305(b)(2)(ii) filed by interested parties in their petitions for rehearing of Order No. 43, the Commission in Order No. 43–A [4] decided to delete the requirement of separate allowables and, instead, issue a notice of proposed rulemaking addressing this issue. In the applications for Rehearing of Order No. 43, several petitioners alleged that the requirement of allowables was an unlawful attempt by the Commission to intrude into the regulatory area or natural gas production which is reserved to the States. Moreover, these petitioners contended that § 271.305(b)(2)(ii) conflicted with existing State procedures. For example, the States of New Mexico and Oklahoma purportedly do not establish allowables for each well in a proration unit; Texas is said to set allowables for each well, but not solely on the basis of the respective ability of the wells to produce.

It was also argued that § 271.305(b)(2)(ii) produced inquitable results, was discriminatory in effect and could not be supported in light of its stated purpose. Finally, the petitioners alleged that § 271.305(b)(2)(ii) was unduly burdensome both administratively and economically to jurisdictional agencies and that the requirements placed in doubt many section 103 determinations which the agencies had already made, but which had not yet become final under § 275.202 of the Commission's regulations.

The Proposed Rule

The Commission herein proposes to issue a new § 271.305(b)(2). As proposed, this regulation would provide that where a second well is drilled in an existing proration unit based upon a finding by the jurisdictional agency that such well is necessary to effectively and efficiently drain the reservoir, and the jurisdictional agency has set allowables for the unit but has not set allowables for each well in the unit, production from such well could still qualify for the section 103 price. However, in such a situation, the producer could not bill the purchaser at the section 103 maximum lawful price for a volume in excess of a volume which bears the same ratio to the total volumes produced from all wells in the unit as the production capability of such new well bears to the aggregate production capability of all wells in such unit. Production capability of the existing and the new wells could be measured by means of a flow test or any other test reasonably designed to calculate the capability of a well to produce natural gas and would not have to be measured more than once per year.

This proposal would allow gas from a second well in a proration unit to qualify for the section 103 price without necessarily requiring a State to set separate allowables for each well in the proration unit. Furthermore, there would not be any limitations on the amount of gas produced from the new well. The producer would have the flexibility to produce any portion of the allowable from either well; however, if he chose to produce a disproportionate volume from the new well, he could not price the new well's entire volume at the section 103 price. Moreover, this new qualification would not apply if the State does set allowables for the unit and has also set allowables for each well consistent with its regulatory policies. Nor would the qualification be applicable if the State does not set allowables for the proration

[4] Order Granting In Part and Denying In Part Rehearing of Order No. 43 and Amending Regulations, Docket No. RM79–72, issued November 16, 1979, Mimeo., pp. 14–16.

unit. Thus, this regulation would recognize the right of the State to set allowables for each well in the proration unit in accordance with its own regulatory policies.

The Commission proposes to make § 271.305(b)(2) as proposed applicable to deliveries of natural gas made on or after the effective date of any final rule issued in this Rulemaking. The Commission recognizes, however, that its decision to proceed with this rulemaking subsequent to establishment of the fnial rules implementing section 103 may create difficulties for producers which may arise, for example, in the billing of their purchasers for gas affected by the rule. For this reason, the Commission specifically invites comments identifying any problems which may arise because of the proposed effective date of this rule.

Written Comment Procedure

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies of any filing made in this docket should be filed witha the Secretary of the Commission. All comments received prior to January 23, 1980, will be considered by the Commission prior to promulgation of any final regulation issued as a result of this proceeding. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NE., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should refer to Docket No. RM80-12.

Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on December 17, 1979, beginning at 10:00 a.m., and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provied that a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m. on December 12, 1979.

Requests to participate in the hearing should include a reference to Docket Number RM80-12 as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m. on December 14, 1979. The presiding officer is authorized to limit oral presentation at athe public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 30 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel, composed of members appointed by the Chairman, may question such persons and any interested persons may submit questions to the presiding officer to be asked of persons making statements.

The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; Exec. Order No. 12,009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Subpart C of Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 271.305 is amended by inserting paragraph (b)(2) to read as follows:

§ 271.305 Special rule applicable to existing proration units. * * *

(b) *Wells spudded on or after February 19, 1977.* * * *

(2) Where the explicit finding of subparagraph (1) of this paragraph is that both an existing well and a new well are necessary to effectively and efficiently drain the reservoir covered by the proration unit and the appropriate State agency having regulatory authority has established an allowable or production level for the unit but not for each well on the unit, the producer may not bill the purchaser at the maximum lawful price under this subpart for a volume in excess of a volume which bears the same ratio to the total volumes produced from all wells in the unit as the production capability of such new well bears to the aggregate production capability of all wells in such unit.

Proposed Regulations

45 Federal Register (1980)

¶ 32,050 Revision of Monthly Statements of Electric Utility Companies, Form No. 5, and of Natural Gas Pipeline Companies, Form No. 11

45 F. R. 48 (January 2, 1980).

18 CFR Parts 141 and 260

[Docket No. RM80-17]

Revision of Monthly Statements of Electric Utility Companies, Form No. 5, and of Natural Gas Pipeline Companies, Form No. 11

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission gives notice that it proposes to revise its monthy reports, Form No. 5, Monthly Statement of Electric Operation Revenue and Income (18 CFR 141.25) and Form No. 11, Natural Gas Pipeline Company Monthly Statement (18 CFR 260.3) in order to eliminate reporting burdens on the jurisdictional regulated industry indicated to be unnecessary by the validation program. The revisions are proposed to be effective for monthly reporting for periods beginning January 1, 1980 and continuing thereafter.

DATE: Written comments by January 21, 1980.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Reference Docket No. RM80-17.

FOR FURTHER INFORMATION CONTACT:

James Kitchen, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3508N, Washington, D.C. 20426, (202) 357-9212.

Elaine M. Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3405N, Washington, D.C. 20426, (202) 357-9190.

Issued: December 21, 1979.

I. Background

The Commission is engaged in an ongoing effort to eliminate unnecessary burdens on the industries regulated by it. This rulemaking is part of that effort.[1] All data elements contained in forms submitted to the Commission are being evaluated to determine which data is needed by the Commission to carry out its regulatory functions. The results of this evaluation are reflected in the revisions proposed herein, for the Form No. 5, Monthly Statement of Electric Operating Revenue and Income (18 CFR 141.25), and the Form No. 11, Natural Gas Pipeline Company Monthly Statement (18 CFR 260.3)

Form No. 5 is a one page report designed to obtain monthly information primarily concerning electric operating revenues, expenses and sales. At present, 233 publicly and privately owned electric utilities report the 118 data items in Form No. 5 monthly.

Form No. 11 contains seven tables on five pages, with requests for information primarily concerning natural gas pipeline operating sales, revenues, expenses, and refund obligations. There are 464 data items on this form which are now reported by 33 major gas pipelines companies.[2]

[1] *See* Order No. 53, Docket No. RM 79-38, issued October 23, 1979, and Notice of Proposed Rulemaking, Docket No. RM80-2, issued October 23, 1979.

[2] A major gas pipeline company, as used here, is a natural gas company whose combined gas sold for resale and gas transported or stored for a fee exceeded 50 million MCF at 14.73 psia (60°F) in the previous year. 18 CFR 260.3.

The Energy Information Administration collects these data forms and publishes statistics from them. In addition, there are several data items on both the Form No. 5 and Form No. 11 which are collected for the U.S. Department of Commerce. By Order No. 503, issued January 29, 1974, Docket No. RM74–5, the Commission agreed to collect these data items to assist the Bureau of the Census in compiling current data on a monthly basis.

As a result of the Commission's in-depth review of both the data items and its current regulatory mission, the Commission has determined that it no longer needs certain data collected by the present Forms No. 5 and No. 11. The Energy Information Administration, the agency responsible for collecting this data, may decide to continue collection of any data item here for its own or another agency's purposes. However, if all these items are eliminated, the result would be an estimated eighty percent reduction in reporting burden to persons subject to the reporting requirement under Form No. 5 and in an estimated sixty percent reduction under Form No. 11.

Because of the minor nature of these proposed revisions and because early adoption will expedite reduction of unnecessary reporting burdens, the Commission proposes to make the revisions effective for monthly reporting for periods beginning January 1, 1980 and continuing thereafter.

II. Summary of Revisions

The following is a brief description of the proposed revisions to each of the forms:

Form No. 5

Out of the 118 data items now requested by Form No. 5, the Commission proposes to eliminate 89 data items. We have eliminated the requirement of reporting previous year data (59 items) since this data can be retrieved easily from prior filings for statistical publication purposes. Approximately thirty other data items relating primarily to income and expenses are being proposed for deletion because the validation study has confirmed that the Commission no longer needs this information for regulatory purposes.

The Commission proposes to retain the twenty-five data items regarding sales of electric energy for the current period only. Reporting will continue to include revenues in thousands of dollars, Mwh sales and the number of customers by the classes of service.

The Department of Commerce has requested that we continue to collect four selected items (line items 10–13, Attachment A) in order to continue to supply monthly statistical needs. The Commission acknowledges the continued necessity of its performing this collection responsibility for the Department of Commerce.

In addition, the Commission finds that the revenue limit used to describe which companies are required to file can be raised from the existing $2.5 million minimum [3] to a $100 million minimum. The Commission believes that it will continue to obtain a valid statistical sampling of data for regulatory needs. The proposed limit will be effective for all privately owned electric utilities with annual electric operating revenues of $100,000,000 or more. Certain other privately-owned and other publicly owned utilities as specifically designated on Form No. 5 also will be required to file in order that representative data concerning energy sales from all states will be collected.

As an added feature in response to previous industry complaints regarding lack of space on the form, the Commission proposes to add a section on page 2 for footnotes. Finally, in order to conform with other form titles, the title of Form No. 5 is being changed to the "Electric Utility Company Monthly Statement."

The Energy Information Administration has requested that the reporting period for Form No. 5 be

[3] "[A]ll Class A electric utilities, both privately and publicly owned." 18 CFR 141.25; *see* 18 CFR 101.

shortened from the current requirement of 40 days at the end of the reported month to 20 days. The Energy Information Administration believes that this shortened period is desirable in light of the proposed reduction in reporting burden because it will enable them to publish more current statistical data. In response to their request and in order to permit public comment to aid the Commission in evaluating the practicality of this suggestion the Commission has included this reduced time period in the proposed rule.

Form No. 11

The Commission proposes to eliminate approximately 294 data items from the 464 items now required. The validation study indicates that the reduction can be made without hampering Commission functions. This proposal represents an estimated sixty percent reduction in the reporting burden of the Form No. 11.

Data regarding details of operations and maintenance expenses makes up the largest portion of the 170 retained items. Other retained data items consist mostly of selected data on Sales of Natural Gas (revenues are reported in thousands of dollars and volumes are reported in millions of cubic feet) and of other plant and refund data. In addition, a separate page for footnotes has been added.

The Department of Commerce has requested that the Commission also continue to collect the same selected 4 data items regarding natural gas companies (line items 3, 8 and 10 of Table 2 and line item 4 of Table 3, of Appendix B) as were requested for the electric utilities. The Commission continues to believe that the Monthly Reports are the most appropriate vehicles with which to collect the data requirements for the Department of Commerce.

The Energy Information Administration has requested that the reporting period for Form No. 11 be shortened from the current requirement of 40 days at the end of the reported month to 20 days for the same reasons cited above in the discussion of Form No. 5. In response to their request and in order to permit public comment to aid the Commission in evaluating the practicality of this suggestion, the Commission has included this reduced time period in the proposed rule.

III. Comment Procedures

The Commission invites interested persons to submit written comments on this proposal. Copies of all comments will be furnished to the Energy Information Administration for its use. The Commission specifically requests that commenters address the following questions:

1. Do the proposed revisions or eliminations of required data affect any Commission or State regulatory functions?

2. Is there any reason for continued collection of the data for the purposes of another Federal agency? Suggestions for the continued collection of data which has been proposed for elimination from the present Forms No. 5 and No. 11 should identify the proper agency and the purpose for collection of the data.

3. Comments are requested on the practicality of meeting the new proposed filing deadline.

Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should refer to Docket No. RM80–17. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, January 21, 1980, will be considered by the Commission prior to promulgation of final regulations. Pursuant to 44 U.S.C. 3501–3511, these proposed revisions will be considered by the Office of Management and Budget for ultimate clearance. Interested persons wishing to have their comments considered during this clearance process should submit copies of their comments to the Commission to the Clearance Office of Regulatory Policy and Reports Management Divisions, Office of Management Division, Office of Management and Budget, Washington, D.C. 20503. All written submissions will be placed in the public file which has been established in this docket and

which is available for public inspection during regular business hours in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

(Natural Gas Act, as amended, 15 U.S.C. 717–717w; Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, Pub. 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267 (September 15, 1977).)

In consideration of the foregoing, the Commission proposes to revise Form No. 5, Monthly Statement of Electric Operating Revenue and Income, prescribed by § 141.25, Chapter I, Title 18 of the Code of Federal Regulations and Form No. 11, Natural Gas Pipeline Company Monthly Statement, prescribed by section 260.3, Chapter I, Title 18 of the Code of Federal Regulations as set forth in Attachment A and B, hereto.

In addition, in consideration of the foregoing, the Commission proposes to revise Parts 141 and 260 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.[4]

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 141.25 is revised to read as follows:

§ 141.25 FERC Form No. 5, Electric Utility Company Monthly Statement.

(a) This form, which is applicable to the electric utility companies designated therein, is designed to obtain on a monthly basis information concerning sales of electric energy and certain other selected items of income and plant.

(b)(1) *Who must file.* Each privately and publicly owned electric utility, as designated in the FERC No. 5, shall prepare and file with the Commission for the month beginning January 1, 1980 and for each month thereafter an original and 2 copies of the FERC Form No. 5.

(2) *When to file.* Such reports shall be filed within 20 days after the end of the reported month and shall be signed by the Chief Accounting Officer of the reporting company, but are not required to be under oath.

2. Section 260.3 is revised to read as follows:

§ 260.3 FERC Form No. 11, Natural Gas Pipeline Company Monthly Statement.

(a) This form, which is applicable to natural gas companies designated therein, is designed to obtain on a monthly basis information concerning selected revenues, income statements, and other items, as well as details of operation and maintenance expenses.

(b)(1) *Who must file.* Each natural gas company, as defined in the Natural Gas Act, whose combined gas sold for resale and gas transported or stored for a fee exceeded 50 million Mcf at 14.73 psia (60° F) in the previous calendar year, shall prepare and file with the Commission for the month beginning January 1, 1980 and for each month thereafter an original and 2 copies of the FERC Form No. 11.

(2) *When to file.* Such reports shall be filed within 20 days after the end of the reported month and shall be signed by the Chief Accounting Officer of the reporting company, but are not required to be made under oath.

[4] Copies of these forms are available from the Commission's Division of Public Information, as attachments to the "Notice of Proposed Rulemaking".

¶ 32,051 Statewide Exemptions From Incremental Pricing

45 F. R. 1081 (January 4, 1980).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 282

[Docket No. RM79-47]

Statewide Exemptions From Incremental Pricing

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTIONS: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes a procedural rule under which a State may apply for Statewide exemption from the incremental pricing program required by the Natural Gas Policy Act of 1978. An exemption application will be treated as a proposed rule and made subject to public comment. If the Commission determines that the purposes of incremental pricing would be as well advanced by the State program as by the Commission's incremental pricing rules, the State program will be submitted to Congress, and will take effect if neither House disapproves it.

A distinction is made in the Notice between State exemptions from incremental pricing and State-level incremental pricing. States setting rates and charges paid by incrementally priced users at the alternative fuel ceiling price are accomplishing the primary objective of incremental pricing. States need not obtain any formal Commission approval or exemption from Title II of the NGPA in order to effect incremental pricing at the State-level rather than at the interstate pipeline-level.

COMMENT DATE: February 15, 1980.

HEARING DATE: February 5, 1980.

FOR FURTHER INFORMATION CONTACT:
Walter W. Schroeder, III, Executive Assistant to the Chairman, Federal Energy Regulatory Commission, Room 9000, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8335.
Nancy Williams, Deputy Assistant General Counsel for Regulatory Development, Federal Energy Regulatory Commission, Room 8100-I, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8130.

I. Introduction

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that the Federal Energy Regulatory Commission (the Commission) promulgate regulations under which interstate pipelines and their local distribution company customers must channel a specified portion of the acquisition costs of natural gas to industrial users. The "incremental costs" of natural gas are to be passed through from the supplier to the industrial facility by means of a surcharge pricing mechanism. Final regulations implementing the statutory requirements for incremental pricing of industrial boiler fuel use were issued by the Commission on September 28, 1979 (44 F.R. 57726, October 5, 1979). The regulations issued on September 28 were contained in two dockets, Docket Nos. RM79-14 and RM79-21.

In the course of developing these rules, several commenters suggested that the Commission consider allowing, in appropriate circumstances, state-wide exemptions from incremental pricing. In response to these suggestions, the Commission on June 5, 1979, opened Docket No. RM79-47 for the purpose of receiving comments on whether a separate rulemaking proceeding should be established with respect to state-wide exemptions from incremental pricing (44 FR 33100-33101, June 8, 1979).

Comments received in this docket lead the Commission to believe that rules providing for state-wide exemptions from incremental pricing may be in the public interest. We are therefore issuing this Notice of Proposed Rulemaking to solicit specific comments

on the advisability and content of any Statewide exemption. The Commission also believes that Section 206(d) of the Natural Gas Policy Act gives the Commission statutory authority to provide such state-wide exemptions. This statutory exemption provision requires that any exemption rule be submitted to Congress and may take effect only if neither House disapproves the rule during a 30-day review period.[1]

II. State Response to Incremental Pricing

On the basis of comments and other information received by the Commission in connection with incremental pricing, several States have proposed or taken action in response to the Commission's implementing regulations. These State responses appear to fall into two general categories.

One type of response is for the State to alter its rate structure, specifically setting the price of natural gas to non-exempt (incrementally priced) users at the alternative fuel cost as referenced in the Commission's regulations and published each month by the Energy Information Administration of the Department of Energy. A second type of response, apparently under consideration in a number of States, consists of State programs that might depart from the Commission's rules either as to the formula by which surcharges are apportioned among users subject to incremental pricing or as to the manner in which the maximum surcharge absorption capability (MSAC) of incrementally priced users is computed.

Any State taking the first course of action would eliminate any maximum surcharge absorption capability (MSAC) of non-exempt users in that State. It is asserted by various commenters that if a State takes this action, end users and local distribution companies located in the State should be excused from any further requirements imposed by Part 282 of the Commission's regulations (relating to accounting and reporting requirements in connection with incremental pricing).

The second type of response to the Commission's incremental pricing rules could occur where a State would desire to institute an innovative scheme for pricing natural gas and where the scheme would differ from the incremental pricing program promulgated by the FERC. It is argued by some commenters that the Commission should exempt States from the requirements of Title II only if the State's alternative regulatory program will achieve the same objectives that underly Title II of the NGPA.[2]

III. State-level Incremental Pricing

As noted, one response of some states to federally-imposed incremental pricing is to change State laws in order to set the price of gas for non-exempt uses, as defined by the Commission, at the applicable alternative fuel ceiling price. If a State raises the rates and charges for natural gas used by non-exempt users to the alternative fuel ceiling, the maximum surcharge absorption capability (MSAC) of those users becomes zero, so that they no longer contribute to recovering the interstate pipeline supplier's incremental gas cost account. The effect of this action on the part of any State is to cause the entirety of revenues collected from non-exempt users to remain within that State. Because the Commission's rules operate at the interstate level, incremental surcharges paid by non-exempt users in one State will contribute to a reduction

[1] (d) Other Exemptions:

(1) In general.—The Commission may, by rule or order, provide for the exemption, in whole or in part, of any other incrementally priced industrial facility or category thereof from the rule prescribed under section 201 (including any amendment under section 202 to such rule).

(2) Congressional Review.—Any rule which provides for any exemption under this subsection may take effect after the expiration of the first 30 calendar days of continuous session of Congress (determined in accordance with section 507(b)) after a copy of such rule has been submitted to each House of Congress, unless, during such 30 day period of continuous session of Congress, either House of the Congress adopts a resolution of disapproval described in section 507(c)(3), with respect to such rule. (Natural Gas Policy Act, Section 206(d)).

[2] The objectives of Title II are summarized below, in Section V.

in the amount of purchased gas costs to be recovered from exempt users served by the pipeline, regardless of the State in which those exempt users are located. Some commenters have argued that the result of State-level incremental pricing is unfair; that there should be a State-by-State balancing of incremental pricing benefits to all exempt users.

Other commenters have pointed out that, even prior to enactment of the NGPA, some States had practiced a policy of pricing low priority users at or near the price of alternative fuel oil. The existing disparity of State pricing policies, coupled with the requirements of Title II, will inevitably result in the impact of incremental pricing on natural gas ratepayers to differ from one State to another. Unless commenters would argue that the NGPA requires that this Commission eliminate existing differences in State ratemaking practices, it would seem that these differences pose an issue that transcends incremental pricing and that Congress had no intention of neutralizing these imbalances through incremental pricing.

The fact that the distribution of benefits among exempt users is different when States raise non-exempt user prices to the alternative fuel ceiling than when these prices are imposed through interstate pipeline surcharges does not override the Commision's present willingness to permit States to pursue legal and logical policies for regulating the price of natural gas at the State level.

The Commission is also of the view that action by States to raise non-exempt user rates to the alternative fuel ceiling is fundamentally consistent with the purposes of incremental pricing. The thrust of Title II of the NGPA is to increase the cost of gas in price-sensitive industrial uses. With respect to non-exempt uses, Title II requires surcharge passthrough to the burner tip[3]; with respect to exempt users, Title II reflects a clear Congressional intent for incremental pricing to mitigate the impact of rising wellhead prices on residential and other customers. Because it is within the capability of States practicing State-level incremental pricing to use any increased revenues derived from non-exempt users, it is the Commission's expectation that States will cause this Congressional intent to be realized.

Section 205 of the NGPA prevents States from lowering rates to non-exempt users but is silent on the question of whether States may take the opposite action—to raise those rates. However, the Statement of Managers specifically appears to contemplate State action to increase industrial gas prices:

> The conference agreement does not preclude State regulatory agencies from exercising their authority under State law to regulate local distribution companies. A State regulatory agency could for example, raise prices to be paid by incrementally priced industrial facilities to levels higher than the levels required by this Title. The conferees have not mandated such a practice; nor has it been precluded. State law is not preempted in this case and States may wish to place more of the costs of service onto a particular class of industrial users. The conferees make no judgment as to the advisability of this action.
>
> A State regulatory agency may wish to provide for some form inverted rate schedules, or other rate-making technique, to provide for recovery of the costs required to be passed through under this Title. So long as the costs are passed through to the incrementally priced industrial facilities covered by the required rule, the State may use whatever ratemaking technique it so desires. The basic requirement of this Title is to recover the surcharge from the identified class of incrementally priced industrial facilities.[4]

In sum, the Commission believes that the Congress has already addressed and affirmed the substitution of State-level incremental pricing (through increased rates to non-exempt users) for incremental pricing pricing at the interstate pipeline level. These considerations lead the Commission to a

[3] This requirement is contained in sections 204 and 205 of the NGPA.

[4] House of Representatives Report No. 95-1752, October 10, 1978, pp. 100-101.

preliminary view that it should not, and legally cannot, prevent States from raising rates of non-exempt industrial users at or above the federally-prescribed and published alternative fuel cost. However, the Commission recognizes that some commenters hold a contrary view, and requests, therefore, that parties commenting on this proposed rule address the questions of (a) whether the NGPA permits States to increase rates of incrementally priced users to the alternative fuel ceiling and (b) whether the NGPA requires that States use the increased revenues from incrementally priced users to offset rates and charges to exempt users.

IV. Proposed Elimination of Reporting Requirements Under State Level Incremental Pricing

The Commission does not believe it necessary for States to seek formal Commission or Congressional approval in order to effect State-level incremental pricing. The Commission does propose herein to entertain applications from States undertaking State-level incremental pricing to eliminate reporting requirements that would otherwise continue to be imposed by the Commission's incremental pricing regulations. Absent relief from reporting requirements set forth in Part 282 of the Commission's regulations, local distribution companies will have to make monthly reports of aggregate MSAC's to their pipeline suppliers, even though these MSAC's will be zero.

When reporting relief is granted, local distribution companies located in a State engaged in State-level incremental pricing will no longer be required to undertake such reporting, and shall be considered to have reported zero MSAC's for purposes of Part 282.

Any State seeking an elimination of reporting requirements under the Commission's incremental pricing rules must file with this Commission a letter from the State agency having authority over rates and charges for natural gas service certifying that rates and charges to each non-exempt industrial user (as defined by the Commission) located within that State are now and will remain at or above the alternative fuel ceiling price.[5] Specifically, the delivered price to these users in any billing month must be no lower than the alternative fuel ceiling price published by the Energy Information Administration on or about the 20th of the preceding month. Finally, the State agency must certify that it will notify this Commission if any change in law or policy is adopted such that rates to non-exempt users will no longer equal or exceed the alternative fuel ceiling.

Any party that has reason to believe that a non-exempt user located in a State having certified that non-exempt user rates will be at or above the alternative fuel ceiling is actually receiving gas service at a lower price may file a complaint with this Commission. The Commission will investigate the issues alleged in the complaint, and will take appropriate action. The Commission specifically requests comments on any monitoring and enforcement provisions which may be necessary in order to assure that non-exempt users actually pay rates not less than the applicable alternative fuel ceiling.

V. Statewide Alternatives to Incremental Pricing

The Commission is also willing to entertain proposed State exemption plans that do not meet the criteria of state-level incremental pricing outlined above and which are therefore truly exemptive in character. In the interest of encouraging States to consider the broadest range of alternatives to the statutorily-defined incremental pricing regime, the Commission will not attempt at this time to define or limit the types of State programs that merit consideration. But by way of illustration, such programs might provide for an

[5] Reporting relief will not be granted solely on the basis that a State intends to adopt conforming rates at some future point in time. Only after the State agency certifies that non-exempt user rates are at or above the alternative fuel ceiling will the reporting relief be granted.

alternative method of allocating incremental pricing surcharges among users in the State who are subject to incremental pricing. The Commission's regulations require that this allocation occur on a volumetric basis until the alternative fuel ceiling price is reached. States seeking to depart from the Commission's rules and instead to allocate more of the surcharges to some non-exempt users and correspondingly less of the surcharges to other non-exempt users (as might be involved in an "auction" or bidding approach) could pursue this course through an alternative incremental pricing program.

Notwithstanding the previously-quoted section of the Statement of Managers relating to section 205 indicating that States are free "to provide for some form of inverted rate schedules, or other rate-making technique" for surchage recovery, the Commission is concerned that inverted rates, even if they result in the full aggregate recovery of incremental pricing surcharges from non-exempt users in the State, may not meet the separate requirements of section 204 (c)(3)(B).

Inverted rates designed to fully reflect aggregate MSAC's within the State would presumably consist of one or more blocks at a price below the alternative fuel ceiling and one or more blocks priced above the ceiling. The probably result of such a rate program is that, in any given month, the actual average delivered price of gas to "conserving" non-exempt users (who successfully avoid the higher-priced rate blocks) will be below the alternative fuel ceiling. Other non-exempt users unable to avoid higher rate blocks might pay more, on average, than the alternative fuel ceiling price.

A problem arises from the fact that section 204(c)(3)(B) appears to permit an interstate pipeline to eliminate or reduce its unrecovered incremental pricing surchage account, through "spillover" into the general PGA account, only if such reductioin is necessary in order to prevent the price of gas to any nonexempt customers from exceeding the alternative fuel ceiling. The problem is with the wording of the section, which appears to refer to non-exempt users individually rather than as a class.* The Commission is in doubt as to the extent to which the statutory language and the Statement of Managers are in conflict, and invites comment on this matter.

Another category of State alternatives to statutory incremental pricing might provide for modified definitions of the maximum surcharge absorption capability of incrementally-priced users in the State. Proposals to redefine the category of non-exempt users or to apply an alternative fuel ceiling price other than the one imposed by the Commission's regulations would fall into the category of alternative MSAC formulations.

The essential difference between the two types of State alternatives illustrated above is in the degree of departure from the statutory incremental pricing program. In the first illustration, aggregate incremental surcharges recovered from the class of all non-exempt users within the State is no different from the statutory program. In effect, any differences in impact are confined within the State. The second type of alternative State program involves changes of a larger dimension, and could produce impacts that affect other customers in other States. Accordingly, the more a State alternative plan departs from statutory incremental pricing, the greater will be the amount of scrutiny given by the Commission to such a plan. This approcah will assure that any

* Section 204 (c)(3)(B) reads as follows: Elimination or reductioin of surcharge applicable to a facility.—The rule under section 201 (including any amendment under section 202 to such rule) shall provide one or more methods which have the effect of elimianting or reducing the amount of the surcharge determined under subparagraph (A) to be passed under paragraph (2) with respect to volumes of natural gas to be delivered directly or indirectly to *any incrementally priced industrial facility* for industrial use to the extent that such surcharge, in the absence of such elimination or reduction, would cause the rates and charges, per million Btu's, paid for such volumes of natural gas by that incrementally priced industrial facility to exceed the appropriate alternative fuel cost. (emphasis added)

alternative plans ultimately referred to Congress can be fully understood and justified.

The Commission seeks to provide a broad measure of flexibility and creativity to States seeking exeptions from incremental pricing. If a State can show that it could accomplish the purposes of incremental pricing through means other than prescribed by the Commission's rules, the Commission will seriously consider this request. On the other hand, exemptions will not be granted to States simply on the basis that Federally-imposed incremental pricing imposes administrative or other burdens. It will be incumbent upon any State seeking an exemption from the requirements of Title II to show that the purposes underlying Title II will be as well or better advanced by State action than by imposition of the Commission's rules under Title II.

The purposes of Title II of the NGPA, as perceived by the Commission, are discussed at length in the Notice of Proposed Rulemaking on the so-called Phase II incremental pricing rule issued by the Commission on November 15, 1979 in Docket No. RM80–10 (44 FR 67170, November 23, 1979).

Rather than repeat the discussion of purposes contained in that Notice of Proposed Rulemaking, this Notice will merely point out that there appear to be two major purposes of incremental pricing. The first purpose is to raise the price of natural gas delivered to industrial users to a sufficiently high level that such users will motivate their pipeline suppliers to refrain from bidding up the price of deregulated natural gas or relying excessively on the regulated gas categories with high ceiling prices. Congress sought to use incremental pricing as a means of achieving an orderly transition to wellhead price deregulation in 1985. Any incentive on an interstate pipeline to bid higher than longrun market clearing prices for additions to pipeline supplies would be lessened if incremental pricing threatened to cause industrial customers to switch to alternative fuels, thereby reducing the marketability of that gas.

A second purpose of incremental pricing is to shelter residential and other high priority natural gas consumers from the full near-term impact of wellhead price increases permitted by the NGPA. This effort to mitigate price impacts on non-industrial customers is accomplished by recovering a greater proportion of interstate pipeline purchased gas costs from users subject to incremental pricing than from other users.

The Commission intends to treat any formally proposed state-wide alternative plan as a proposed rule. Upon its receipt, by the Secretary of the Commission, the plan will be treated procedurally as if it were a Commission-proposed rule. The proposal will be noticed for comment. On the basis of comments received and its own analysis, the Commission would then either approve the plan and submit it to the Congress for review, or discontinue the rulemaking. As discussed earlier, the standard against which the Commission proposed to review State alternative plans is whether the purposes underlying Title II would be as well or better advanced under the plan. Commenters are invited to address the Commission's proposed procedure and standards for reviewing State alternatives to incremental pricing.

VI. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should reference Docket No. RM79–47. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, February 15, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North

Capitol Street, NE., Washington, D.C., 20426, during regular business hours.

B. *Public Hearing.* A public hearing on this proposed rule will be held on February 5, 1980, beginning at 10:00 a.m. EST at the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing. Interested persons may also obtain this information by calling the Office of the Secretary of the Commission.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, no later than seven days prior to the hearing. Requests should reference Docket No. Rm79–47, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Office of Public Information three days before the hearing and will be available at the site of the hearing on the morning it is convened.

The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit question to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available in the public file for this proceeding, Docket No. RM79–47 in the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq*)

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

¶ 32,052 Notice of Proposed Rulemaking to Review Report of Gas Supply and Requirements: Form No. 16

45 F. R. 5309 (January 23, 1980).

18 CFR Parts 3 and 260

[Docket No. RM80-20]

Notice of Proposed Rulemaking to Review Report of Gas Supply and Requirements: Form No. 16

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: By this Notice, the Federal Energy Regulatory Commission proposes to amend Form No. 16 (Report of Gas Supply and Requirements). The proposed amendments include changing the number of schedules contained in the Form, the format of those schedules, and the instructions which accompany the schedules. The proposed changes are a product of the Commission's ongoing effort to eliminate unnecessary reporting burdens and to update its forms.

DATE: Comments due February 29, 1980.

ADDRESS: Comments to this Notice should be addressed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 and should reference Docket No. RM80-20.

FOR FURTHER INFORMATION CONTACT: Robert Schroeder, Office of Pipeline and Producer Regulation, Curtailment Branch, Room 7300-B, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357-8864.

Issued January 18, 1980.

The Federal Energy Regulatory Commission (the Commission) is engaged in an ongoing effort to eliminate unnecessary reporting burdens. This rulemaking, to amend Form No. 16, "Report of Gas Supply and Requirements," is a part of that effort and reflects an evaluation of data needed by the Commission to carry out its regulatory functions. The proposed amendments to the content, format and instructions of Form No. 16 should result in a significant reduction in respondent burden and improve the quality of the responses filed under Form No. 16.

A. Background

Form No. 16 is submitted by natural gas pipeline companies making sales in interstate commerce.[1] It is a semiannual report showing system-wide summary information of a pipeline's gas supplies, requirements, and curtailments. This information is given by months, for one year of actual experience and for one year of future projections. In addition, the Form requires, on the same basis, detail on deliveries, requirements and curtailments for each customer of a respondent receiving 100,000 Mcf of gas per year or more. Customers receiving less than 100,000 Mcf of gas per year report the same information on an aggregate basis.

Form No. 16 gives the Commission information necessary to provide for emergency sales and certificates and to review curtailment plans and revisions. The form, in conjunction with the biweekly telephone survey of 29 major interstate pipelines conducted during

[1] Form No. 16 was initially promulgated in 1973; Order No. 489, "Order Requiring Report of Supply and Requirements and Promulgating Schedule", Docket No. R-472 (issued Aug. 24, 1973), 38 FR 23516 (Aug. 31, 1973), 50 FPC 561 (1973). It has been revised but once since that date, Order 523, "Order Amending Section 260.12 of Part 260, Statement and Reports (Schedules)", Docket No. R-472 (issued Feb. 6, 1975), FR 53 FPC 352 (1975). That revision added schedule 1-A to the form and made certain conforming amendments to the accompanying instructions.

the heating season, is used to evaluate, monitor, anticipate, manage, and report on short-term gas supplies, requirements, and imbalances. The Form is also an integral part of annual proceedings to evaluate the impact of natural gas shortages of interstate pipelines.[2] Products of these proceedings include an annual publication providing a national summary and detailed pipeline-by-pipeline assessment of anticipated supply and demand problems[3] and a semiannual report providing an overview of selected elements of Form No. 16.[4] Copies of Form No. 16 must be filed with customers and state regulatory commissions, giving it wide circulation to industry, the public, and the government.

Form No. 16 was last revised in 1975.[5] Since that date the Commission has benefitted from experience in its use. Furthermore, the Commission's review of regulatory burdens indicates that revisions to the Form can significantly reduce respondent burden and make the filing of the Form more concise and facilitate its use. Finally, the Commission should revise Form No. 16 so that its definition and data requests conform to recent regulations which implement the Natural Gas Policy Act of 1978 (NGPA).[6]

B. Summary of Proposed Changes

Form No. 16 is now composed of five schedules: Schedule 1 (Summary); Schedule 1-A (Requirements of Customers of Reporting Pipeline); Schedule 2 (Sources of Present Supply Adjusted for Losses); Schedule 3 (Firm Requirements); and Schedule 4 (Storage Operations). The instructions now require that each of the five schedules must be used twice; first, to report 12 months of actual experience; and second, to report 12 months of projected experience. Thus respondends must file ten schedules. The Commission proposes to reduce the number of schedules which must be filed from ten to eight by revising the schedules and renumbering them so that Schedules 1 through 4 would depict 12 months of actual experience and Schedules 5 through 8 would depict corresponding data for 12 months of projections.

Schedule 1 now consists of two pages. Under this proposal it would be simplified by deleting an obsolete second page. In addition, certain lines would be added to reflect new delivery provisions and to clarify interpipeline deliveries. The instructions would include references to ensure that reporting under the schedule would conform to recently issued regulations respecting certain transportation by interstate pipelines under the NGPA.

Schedule 1-A would be redesignated as Schedule 4 and the information rearranged so that columns (b) through (o) would be consistent with the proposals for other schedules. In addition, major totals would be added for Deliveries, Requirements, and Net Balance to clearly show the correspondence between this schedule and proposed Schedule 1.

Schedule 2 would be revised to reflect more clearly pipeline-to-pipeline surplus or deficiency in deliveries against contracts of pipeline suppliers. Other revisions to give more specificity for additional sources, domestic and imported, are also proposed.

[2] These proceedings, renewed anually each spring since 1975, were recently undertaken: "Order Instituting Proceedings, Establishing Procedures and Providing for Hearings to Evaluate the Impact of Natural Gas Shortages of Interstate Pipeline Companies", Docket Nos. TC79-94, *et al.* (issued Apr. 16, 1979), *as amended*, May 2, 1979 and August 30, 1979.

[3] *See, e.g.*, Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation, *Commission Staff Reports Impact of 1979-80 Winter Curtailment for Twenty-Eight Pipeline Companies* (Sept. 1979).

[4] *See, e.g.*, Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation, *Natural Gas Deliveries, Curtailments and Requirements* (Aug. 2, 1979).

[5] *See*, note 1, *supra*.

[6] *See also* section 304(a)(1)(c) of the Natural Gas Policy Act of 1978 (NGPA) which provides that the President may look to any federal agency to obtain information to carry out his authority under that act.

Current Schedule 3 would be eliminated. It is no longer used by the Commission.

Current Schedule 4 would be redesignated as Schedule No. 3. A volumetric reference, keyed to Gas-in-Place on November 1 would be added as column (p). Storage services would be included in this proposed schedule.

Each of the proposals for the revision of schedules discussed above would apply to actual experience and they would have counterparts for projected or anticipated experience. These counterparts would be designated as Schedules 5 through 8. Thus, the proposed list of new Schedules would be as follows: Schedule No. 1 (Summary of Actual Supply, Requirements and Net Deficiency or Surplus); Schedule No. 2 (Actual Sources of Supply Adjusted for Losses); Schedule No. 3 (Actual Storage Operations); Schedule No. 4 (Actual Deliveries, Requirements and Net Deficiency or Surplus by Customer); Schedule No. 5 (Summary of Projected Supply, Requirements and Net Deficiency or Surplus); Schedule No. 6 (Projected Sources of Supply Adjusted for Losses); Schedule No. 7 (Projected Storage Operations); Schedule 8 (Projected Deliveries, Requirements and Net Deficiency or Surplus by Customer). Copies of these eight schedules are supplied as an attachment to this Notice.

To facilitate the exposition and discussion of these revisions, columns (c) through (l) representing various months have been omitted from the schedules in the attachment.

The Commission also proposes revisions to the instructions and definitions of Form No. 16. The instructions would be consolidated, clarified and expanded to provide respondents with better guidelines on general filing requirements, definitions, and line items on a schedule-by-schedule basis. Some important changes in the proposed instructions include: replacing the term "curtailment" with the more accurate phrase "net deficiency or surplus" of the pipeline (this would be the difference between "net available for market" from the pipeline and "pipeline requirements"); the elimination of the requirement to report monthly volumes on an average daily basis; and the use of more subtotals to overcome past problems users have had with inconsistencies within and among schedules.

Finally, format changes are proposed to ease respondent preparation and to facilitate both public and regulatory uses of the data. These changes include reserving columns (b) through (m) of each schedule for the reporting of monthly volumes; assigning unique schedule numbers to overcome the present ambiguity of using the same schedule number for both actual and projected data; and a reordering of the schedules so that there is a progression from highly aggregated data to supporting detail.

The proposed changes should provide the Commission with more meaningful data in a more usable form. In that the proposed Form prescribes less information and in a more coherent format, reporting burdens should be substantially eased. Because of these advantages it is proposed that the changes described in this Notice should be implemented in time for the report due on April 30, 1980.

In addition to the just-described changes to Form No. 16, the Commission also proposes to amend those regulations which reference Form No. 16. Section 260.12(a) would be amended to designate Form No. 16 as "FERC" Form No. 16. Section 260.12(b) would be revised to reflect the necessity of filing an original and six copies with the EIA. A new section 260.12(c) would be added to provide for waiver of filing for those companies who show that there is good reason for them not to file the form. This provision conforms to past Commission practice respecting the filing of Form No. 16. Finally, a technical correction would be made to § 3.170 (Approved forms, etc.) to remove the redundant subsection (22).

C. Written Comment Procedures

The Commission invites interested persons to submit written data, views and other information concerning the matters set out in this Notice. An

iginal and 14 copies of such comments ould be filed with the Commission by bruary 29, 1980. Comments should be bmitted to the Office of the Secretary. deral Energy Regulatory Commission. 5 North Capitol Street, NE., ashington, D.C. 20426 and should ference Docket No. RM80–20. All written submissions will be placed the Commission's public files and will available for public inspection in the mmission's Office of Public formation, Room 1000, 825 North pitol Street, NE., Washington, D.C. 426 during regular business hours.

Since Form No. 16 will be collected by e Energy Information Administration the Department of Energy, these oposed revisions will be considered the Office of Management and dget for ultimate clearance.

epartment of Energy Organization Act, 42 S.C. 7101 *et seq.*; E.O. 12009, 42 FR 46267; tural Gas Act, as amended, 15 U.S.C. 717 *seq.*)

In consideration of the foregoing, the mmission proposes to amend Form . 16 as set forth in the attachment to s Notice and §§ 3.170 and 260.12, apter I, Title 18 of the Code of Federal gulations as set forth below.

By direction of the Commission.

nneth F. Plumb,

cretary.

.170 [Amended]

1. Section 3.170 is amended by leting the text of paragraph (a)(22) d reserving § 3.170(a)(22) for future e.

2. Section 260.12 is amended to read follows:

60.12 Form No. 16, Report of gas pply and requirements.

(a) The form of Report of Gas Supply d Requirements, designated herein as RC Form No. 16, is prescribed.

(b) Each natural gas pipeline company king sales in interstate commerce of tural gas for resale shall prepare and with the Energy Information lministration an original and six pies of Report of Gas Supply and Requirements, FERC Form No. 16, on or before April 30 and September 30 of each year.

(c) Upon good cause being shown, the Commission will grant requests by any company for waiver of the requirement to file Form No. 16.

3. FERC Form No. 16 and accompanying instructions will be issued as shown in the Attachment of this Notice, saving that, as issued, the forms will contain columns (c) through (l) for monthly data.

Attachment

This attachment contains proposed General Instructions and schedule instructions to accompany proposed Schedules 1 through 4 of Form No. 16. The schedule instructions are identical for proposed Schedules 5 through 8. That is, the instructions for proposed Schedule 1 would be the same as for proposed Schedule 5, those for proposed Schedule 2 the same as for proposed Schedule 6, and so forth. This attachment also contains proposed Schedules 1 through 8 of Form No. 16.

Form 16—Report of Gas Supply and Requirements

I. General Instructions

1. The FERC Form 16, Report of Supply and Requirements is to be filed by interstate natural gas companies making sales in interstate commerce of natural gas for resale.

2. The schedules that are in the Form 16 show system-wide summary information concerning pipeline company supply, requirements, and surplus (or deficiency), by months, for one year of actual experience and one year of projections.

3. Each respondent pipeline will report on or before April 30 and September 30 of each year. In the April 30 filing, actual data for the past year, April through March, and the projected data for one year, April through March, shall be reported. In the September 30 filing, actual data for the past year, September through August, and projected data for one year, September through August, shall be reported.

4. Figures should reflect total MMcf per month in columns (b) through (m), annual total MMcf in column (n), and the peak day MMcf in column (o).

5. Report the peak day volumes for the day of maximum requirements during the reporting period.

6. Report all volumes at 14.73 psia at 60° F.

7. Projections shall be based on normal weather conditions, defined as the latest 30-year average temperature data reported by the U.S. Weather Bureau location nearest to the respondent's service area or areas.

8. Use parentheses () to indicate decreases in supply or deficiencies.

9. Instructions for Schedules 5–8 (projected data) are the same as Schedule 1–4 (actual data).

10. An original and six (6) copies of the report shall be filed with: U.S. Department of Energy, Energy Information Administration, Code 2908, Washington, D.C. 20461.

Each pipeline company shall also send a copy of each of its customers and to each state regulatory commission and state energy office in each state in which it operates.

Schedule No. 1—Summary of Supply Requirements and Net Deficiency or Surplus.

Line by Line Instructions:

01 Net Present Supply—These figures should be transferred from Schedule 2, Line 25.

02 Anticipated New Supply—Anticipated new supply refers to gas not presently flowing but anticipated to be attached during the projected period. An attachment to the Form 16 is to be included, if applicable, specifying anticipated new supply sources and corresponding monthly takes. List each new source by field and/or block and include docket number if certificate authority is presently being sought.

03 Exempted Purchases for System Supply—These purchases refer to gas purchases by an interstate pipeline under Sections 157.45–52, 284.141–148, or 284.161–165 of FERC Regulations for use as general system supply. An attachment is to be included for both the actual and the projected period, if applicable, detailing the seller and the volume of the purchases pursuant to each of the above sections. The aggregate of all such exempted purchases for system supply should be entered on Line 03.

04 SUBTOTAL—Summation of Lines 01, 02, and 03.

05 Normally Anticipated Loss of Supply (Contingency)—Report any allowances made for producer outages, weather related losses, or other losses of supply.

06 Company Use and Shrinkage—Report any company compressor fuel, losses, reductions due to gas or liquid extractions, or unaccounted for gas.

07 Exchange Gas Received or (Delivered)—Report net volume differences in exchange arrangements.

08 Net Storage: (Injection) or Withdrawal—These figures should be transferred from Schedule 3, Line 11 on a monthly basis for columns (b) through (m), as an aggregate annual injuction or withdrawal in column (n), and as a peak day withdrawal in column (q).

09 SUBTOTAL—Summation of Lines 05, 06, 07, and 08.

10 Net Available for Market—This indicates the amount of gas the respondent pipeline has as general system supply for sale to customers. Line 04 less Line 09.

11 Requirements—Each respondent is to state whether their requirements originate from: (a) base period curtailment plan, (b) current contractual obligations, or (c) actual survey of customers' requirements. Do not include transportation services. Respondent must report the requirements which it is currently utilizing to allocate gas.

12 (Deficiency) or Surplus—Refers to the net balance of gas available for market less requirements. Line 10 less Line 11.

13 to 16 Distributor or Customer Self Help Gas Transported to Respondents' Customers—This action shows the extent to which customers of a respondent pipeline are able to acquire supplemental gas supplies. These distributor or self help purchases should be reported under the section they were purchased. Liness 13, 14, and 15 should be treated as mutually exclusive. An attachment is to be included for both the actual and projected period detailing the volumes by customer and type of purchase. This only included sales customers.

13 Exempt Purchases by Respondents' Customers for which a Respondent Pipeline is Transporting—These purchases refer to gas purchases by customers of a respondent pipeline under Sections 157.45–52, 284.141–148, or 284.200–208 of FERC Regulations. The aggregate of all exempted purchases by customers should be entered on Line 13.

14 Direct Assignments to Respondents' Customers Transported by Respondent Pipeline—This refers to assignment gas purchased under Section 284.161–165 of FERC Regulations.

15 Other Gas Purchased by Respondents' Customers and Transported by Respondent Pipeline—Additional gas volumes transported by the respondent pipeline which is purchased under arrangements other than exempt purchases or direct assignments and which is not reported in Lines 13 or 14.

16 SUBTOTAL—Summation of Lines 13, 14, and 15.

17 Total Available to Customers—Line 10 plus Line 16.

18 Other Transportations—Other transportation volumes not reported elsewhere.

19 Deliveries—Show aggregate of all deliveries to other interstate pipeline companies. A separate listing of individual deliveries to interstate pipelines is to be given in Schedule 4. Do not include transportations.

20 Contract or Delivery Obligations—Pipeline to pipeline contract or delivery obligations should be reported on the same basis as requirements stated in Line 11 of Schedule 1. If they are different, footnote the explanation for the discrepancy.

21 (Deficiency) or Surplus—Line 19 less Line 20.

Schedule No. 2—Sources of Supply.

Line by Line Instruction:

01 to 03 Producing Areas—List producing areas by state, except for Louisiana and Texas which are to be additionally broken down for onshore and offshore production.

04 SUBTOTAL—Summation of Lines 01, 02, and 03.

05 to 07 Pipeline Suppliers: Contract Volume by Pipeline—List respondent's contract volumes with each of its pipeline suppliers.

08 SUBTOTAL—Summation of Lines 05, 06, and 07.

09 to 14 Pipeline Suppliers: Deliveries by Pipeline—List actual deliveries from each of the respondent's pipeline suppliers.

15 SUBTOTAL—Summation of Lines 09, 10, 12, 13, and 14.

16 (Deficiency) or Surplus—Line 15 less Line 08.

17 to 19 Other Domestic Sources—Detail if additional domestic sources are SNG, LNG, or other (specify on schedule). Do not include any transportation or exchange volumes.

20 SUBTOTAL—Summation of Lines 17, 18, and 19.

21 to 23 Imports—Detail if imports are LNG, Pipeline, or other (specify on schedule).

24 SUBTOTAL—Summation of Lines 21, 22, and 23.

25 Net Present Supply—Summation of Lines 04, 15, 20, and 24. Transfer these figures to Schedule 1, Line 1.

Schedule No. 3—Storage Operations.

Line by Line Instructions:

01 to 05 Field Name—Include all (injections) or withdrawals of gas in fields owned, operated, leased or used by the respondent pipeline, including customer storage service volumes. Indicate an injection with parentheses.

06 SUBTOTAL—Summation of Lines 01, 02, 03, 04, and 05.

07 to 09 Adjustments—Decreases and/or increases in the above storage volumes due to changes in base storage, development of new zones, or other similar occurrences. Use parentheses () to denote decreases.

10 SUBTOTAL—Summation of Lines 07, 08, and 09.

11 Net Storage—Line 06 less Line 10. Transfer these figures onto Schedule 1, Line 08.

12 to 16 Gas Storage Service—These figures represent customer storage service (injections) and withdrawals. Respondent pipeline can report volumes according to storage service rate schedules or individual customer listings.

17 SUBTOTAL—Summation of Lines 12, 13, 14, 15, and 16.

Column (p)—Working Gas in Place on November 1 should reflect the actual level of the preceding year and forecasted level for the projected year.

Schedule No. 4—Deliveries, Requirements, and Net Deficiency or Surplus by Customer.

General Instructions:

1. List deliveries, requirements, and net (deliveries less requirements) for each direct customer within a specific state on a monthly basis. Sales to interstate pipeline companies should not be included in this section. They are to be listed separately.

2. Customers receiving 100 MMcf or more of gas per year should be listed individually. The remaining customers can be aggregated.

3. Give the total of all deliveries, requirements, and net for each individual state (excluding the sales to interstate pipeline companies).

4. Give a total of all states' deliveries, requirements, and net (again excluding the sales to interstate pipeline companies).

5. List total deliveries, requirements, and net by respondent pipeline to each interstate pipeline served, broken down according to state in which deliveries are made.

6. List total of all deliveries, requirements, and net to interstate pipeline companies.

7. A Grand Total of the Total States and the Total of Interstate Pipelines should be given. The grand total deliveries (line 31) should equal line 10, Schedule 1; the grand total requirements (line 32) should equal line 11, Schedule 1; and the grand total net (line 33) should equal line 12, Schedule 1.

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16 — REPORT OF GAS SUPPLY AND REQUIREMENTS

SCHEDULE NO. 1 - SUMMARY OF ACTUAL SUPPLY-REQUIREMENTS AND NET DEFICIENCY OR SURPLUS

Company Name:

Company Code No.:

PERIOD COVERED: April 1, 19__ to March 31, 19__ / September 1, 19__ to August 31, 19__

Line No.	PIPELINE SUPPLY (a)	Mcf. For March: April / September (b)	...	March / August (a)	Mcf.: ANNUAL TOTAL (n)	PEAK DAY (o)
01	Net Pressent Supply: From Schedule No. 2 Line 23					
02	Anticipated New Supply					
03	Exempted Purchases for System Supply					
04	SUBTOTAL: Lines 1-3					
05	Normally Anticipated Loss of Supply -					
06	Company Use and Shrinkage					
07	Exchange Gas Received or (Delivered)					
08	Net Storage - ((Injection) or Withdrawal): - Schedule 3, Line 11					
09	SUBTOTAL: Lines 5-8					
10	Net Available For Market: Line 4 Less Line 9					
	PIPELINE REQUIREMENTS					
11	Requirements As Defined By One of the Following (Check Appropriate Item): (a) Base Period Curtailment Plan (b) Current Contractual Obligations (c) Actual Survey of Customers Requirements					
	NET BALANCE					
12	(Deficiency) or Surplus: Line 10 Less 11					
	DISTRIBUTION OF CUSTOMER SELF HELP GAS TRANSPORTED TO RESPONDENTS CUSTOMERS BY RESPONDENT					
13	Exempted Purchases					
14	Direct Assignments					
15	Other Gas					
16	SUBTOTAL: Lines 13-15					
17	Total Available to Customers: Line 10 Plus Line 16					
18	Other Transportations					
	SALES BY RESPONDENT TO OTHER INTERSTATE PIPELINES					
19	Deliveries					
20	Contract or Delivery Obligations					
21	Deficiency or Surplus: Line 19 Less Line 20					

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16 — REPORT OF GAS SUPPLY AND WELL OPERATIONS

SCHEDULE No. 2 - ACTUAL SOURCES OF SUPPLY ADJUSTED FOR LOSSES

Company Name:
Company Code No.:
PERIOD COVERED: April 1, 19__ to March 31, 19__ / September 1, 19__ to August 31, 19__

Line No.	SOURCES OF SUPPLY (a)	Mcf, per Month: April / September (b)	. . .	March / August (m)	Mcf: ANNUAL TOTAL (n)	PEAK DAY (o)
	PRODUCING AREAS					
01						
02						
03						
04	SUBTOTAL: Lines 1-3					
	PIPELINE SUPPLIES CONTRACT VOLUME BY PIPELINE - SELLERS NAME AND CODE					
05						
06						
07						
08	SUBTOTAL: Lines 5-7					
	PIPELINE SUPPLIES: DELIVERIES BY PIPELINE					
09						
10						
11						
12						
13						
14						
15	SUBTOTAL: Lines 9-14					
16	(DEFICIENCY) OR SURPLUS: Line 15 Less Line 8					
	OTHER DOMESTIC SOURCES					
17	SNG					
18	LNG					
19	Other _____					
20	SUBTOTAL: Lines 17-19					
	IMPORTS					
21	LNG					
22	PIPELINE					
23	Other _____					
24	SUBTOTAL: Lines 21-23					
25	NET PRESENT SUPPLY: TOTAL Lines 4, 16, 20 and 24					

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16 — REPORT OF GAS SUPPLY AND REQUIREMENTS

SCHEDULE NO. 3 - ACTUAL STORAGE OPERATIONS

Company Name:

Company Code No.:

PERIOD COVERED
April 1, 19__ to March 31, 19__
September 1, 19__ to August 31, 19__

Line No.	STORAGE OPERATIONS (a)	Mcf. per Month (Injections) or Withdrawals: April / September (b)	. . .	March / August (m)	Mcf. ANNUAL TOTAL (n)	PEAK DAY (o)	VOLUMES IN PLACE ON NOV. 1 (p)
	Field Names						
01							
02							
03							
04							
05							
06	SUBTOTAL: Lines 1-5						
	ADJUSTMENTS OR CHANGES IN BASE STORAGE, DEVELOPMENT OF NEW ZONES, ETC.						
07							
08							
09							
10	SUBTOTAL: Lines 7-9						
11	NET STORAGE: Line 6 Less Line 10						
	STORAGE SERVICE SOLD OR RENDERED UNDER STORAGE SERVICE SCHEDULE BY FPC FIELD CODE						
12							
13							
14							
15							
16							
17	SUBTOTAL: Lines 13-16						

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16

SCHEDULE NO 4 - ACTUAL DELIVERIES, REQUIREMENTS AND NET DEFICIENCY OR SURPLUS BY CUSTOMER

Company Name:
Company Code No.:

PERIOD COVERED:
April 1, 19__ to March 31, 19__
September 1, 19__ to August 31, 19__

Line No.	NON-PIPELINE CUSTOMERS OF REPORTING PIPELINE (a)	Mcf, per Month: April September (b)	. . .	March August (b)	Mcf: ANNUAL TOTAL (a)	PEAK DAY (c)	DELIVERY POINT (Name) (d)
01	Deliveries						
02	Requirements						
03	Net						
04	Deliveries						
05	Requirements						
06	Net						
07	Deliveries						
08	Requirements						
09	Net						
	STATE SUBTOTALS						
10	Deliveries: Lines 1, 4 and 7						
11	Requirements: Lines 2, 5 and 8						
12	Net: Lines 3, 6 and 9						
	NON-PIPELINE CUSTOMERS TOTAL ALL STATES						
13	Deliveries: Line 10						
14	Requirements: Line 11						
15	Net: Line 12						
	PIPELINE CUSTOMERS OF REPORTING PIPELINE						
16	Deliveries						
17	Requirements						
18	Net						
19	Deliveries						
20	Requirements						
21	Net						
22	Deliveries						
23	Requirements						
24	Net						
	STATE TOTALS						
25	Deliveries: Lines 16, 19 and 22						
26	Requirements: Lines 17, 20 and 23						
27	Net: Lines 18, 21 and 24						
	PIPELINES CUSTOMERS TOTAL ALL STATES						
28	Deliveries: Line 25						
29	Requirements: Line 26						
30	Net: Line 27						
	ALL CUSTOMERS TOTAL ALL STATES						
31	Deliveries: Lines 13 and 28						
32	Requirements: Lines 14 and 29						
33	Net: Lines 15 and 30						

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16 — REPORT OF GAS SUPPLY AND REQUIREMENTS

SCHEDULE NO. 5 - REPORT OF PROJECTED SUPPLY, REQUIREMENTS AND NET DEFICIENCY OR SURPLUS

Company Name:

Company Code No.:

PERIOD COVERED: April 1, 19__ to March 31, 19__ / September 1, 19__ to August 31, 19__

Line No.	PIPELINE SUPPLY (a)	MMCF Per Month: April / September (b)	. . .	March / August (m)	MMCF: ANNUAL TOTAL (n)	PEAK DAY (o)
01	Net Present Supply: From Schedule No. 2 Line 25					
02	Anticipated New Supply					
03	Prompted Purchases for System Supply					
04	SUBTOTAL: Lines 1-3					
05	Normally Anticipated Loss of Supply -					
06	Company Use and Shrinkage					
07	Exchange Gas Received or (Delivered)					
08	Net Storage - (Injection) or Withdrawal: - Schedule 3, Line 11					
09	SUBTOTAL: Lines 5-8					
10	Net Available For Market: Line 4 Less Line 9					
	PIPELINE REQUIREMENTS					
11	Requirements As Defined By One Of The Following (Check Appropriate Item): (a) Base Period Curtailment Plan (b) Current Contractual Obligations (c) Actual Survey of Customers Requirements					
	NET BALANCE					
12	(Deficiency) or Surplus: Line 10 Less 11					
	DISTRIBUTION OF CUSTOMER SELF HELP GAS TRANSPORTED TO RESPONDENTS CUSTOMERS BY RESPONDENT					
13	Exempted Purchases					
14	Direct Assignments					
15	Other Gas					
16	SUBTOTAL: Lines 13-15					
17	Total Available to Customers: Line 10 Plus Line 16					
18	Other Transportations					
	SALES BY RESPONDENT TO OTHER INTERSTATE PIPELINES					
19	Deliveries					
20	Contract or Delivery Obligations					
21	Deficiency or Surplus: Line 18 Less Line 20					

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16 — REPORT OF GAS SUPPLY AND REQUIREMENTS

SCHEDULE No. 6 - PROJECTED SOURCES OF SUPPLY ADJUSTED FOR LOSSES

Company Name:
Company Code No.

PERIOD COVERED
April 1, 19__ to March 31, 19__
September 1, 19__ to August 31, 19__

Line No.	SOURCES OF SUPPLY (a)	MCF, per Month: April - September (b)	MCF, per Month: October - March (c)	MCF: ANNUAL TOTAL (d)	MCF: PEAK DAY (e)
	PRODUCING AREAS				
01					
02					
03					
04	SUBTOTAL: Lines 1-3				
	PIPELINE SUPPLIERS CONTRACT VOLUME BY PIPELINE - SELLERS NAME AND CODE				
05					
06					
07					
08	SUBTOTAL: Lines 5-7				
	PIPELINE SUPPLIERS: DELIVERIES BY SUBCLINE				
09					
10					
11					
12					
13					
14					
15	SUBTOTAL: Lines 9-14				
16	(DEFICIENCY) OR SURPLUS: Line 15 Less Line 8				
	OTHER DOMESTIC SOURCES				
17	SNG				
18	LNG				
19	Other _____				
20	SUBTOTAL: Lines 17-19				
	IMPORTS				
21	LNG				
22	PIPELINE				
23	Other _____				
24	SUBTOTAL: Lines 21-23				
25	NET PRESENT SUPPLY: TOTAL Lines 4, 16, 20 and 24				

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16 — REPORT OF GAS SUPPLY AND RELATIONSHIPS

SCHEDULE NO. 7 - PROJECTED STORAGE OPERATIONS

Company Name:
Company Code No.:

PERIOD COVERED
April 1, 19__ to March 31, 19__
September 1, 19__ to August 31, 19__

Line No.	STORAGE OPERATIONS (a)	Mcf per Month (Injections or Withdrawals) April September (b)	. . .	March August (m)	Mcf. ANNUAL TOTAL (n)	PEAK DAY (o)	VOLUMES IN PLACE ON NOV. 1 (p)
	Field Names						
01							
02							
03							
04							
05							
06	SUBTOTAL: Lines 1-5						
	ADJUSTMENTS OR CHANGES IN BASE STORAGE, DEVELOPMENT OF NEW ZONES, ETC.						
07							
08							
09							
10	SUBTOTAL: Lines 7-9						
11	NET STORAGE: Line 6 Less Line 10						
	STORAGE SERVICE SOLD OR RENDERED UNDER STORAGE SERVICE SCHEDULE BY FPC FIELD CODE						
12							
13							
14							
15							
16							
17	SUBTOTAL: Lines 12-16						

FEDERAL ENERGY REGULATORY COMMISSION — FERC FORM 16 — REPORT OF GAS SUPPLY AND REQUIREMENTS

SCHEDULE NO 8 - PROJECTED DELIVERIES, REQUIREMENTS AND NET DEFICIENCY OF SUPPLIES BY CENTERS

Company Name

Company Code No.:

PERIOD COVERED: April 1, 19__ to March 31, 19__ / September 1, 19__ to August 31, 19__

Line No.	NON-PIPELINE CENTERS OF REPORTING PIPELINE (a)	MCF per Month: April / September (b)	. . .	March / August (c)	NORMAL TOTAL (e)	PEAK DAY (e)	DELIVERY POINT (State) (f)
01	Deliveries						
02	Requirements						
03	Net						
04	Deliveries						
05	Requirements						
06	Net						
07	Deliveries						
08	Requirements						
09	Net						
	[illegible]						
10	Deliveries: Lines 1, 4 and 7						
11	Requirements: Lines 2, 5 and 8						
12	Net: Lines 3, 6 and 9						
	NON-PIPELINE CENTERS TOTAL ALL STATES						
13	Deliveries: Line 10						
14	Requirements: Line 11						
15	Net: Line 12						
	PIPELINE CENTERS OF REPORTING PIPELINE						
16	Deliveries						
17	Requirements						
18	Net						
19	Deliveries						
20	Requirements						
21	Net						
22	Deliveries						
23	Requirements						
24	Net						
	[illegible]						
25	Deliveries: Lines 16, 19 and 22						
26	Requirements: Lines 17, 20 and 23						
27	Net: Lines 18, 21 and 24						
	PIPELINES CENTERS TOTAL ALL STATES						
28	Deliveries: Line 25						
29	Requirements: Line 26						
30	Net: Line 27						
	ALL CENTERS TOTAL ALL STATES						
31	Deliveries: Lines 13 and 28						
32	Requirements: Lines 14 and 29						
33	Net: Lines 15 and 30						

¶ 32,053 Procedures Governing Applications for Special Relief Under Sections 104, 106, and 109 of the Natural Gas Policy Act of 1978

45 F. R. 5321 (January 23, 1980).

18 CFR Part 271

Docket No. RM79-67

Procedures Governing Applications for Special Relief Under Sections 104, 106, and 109 of the Natural Gas Policy Act of 1978; Request for Public Comments and Notice of Public Discussion on Certain Issues Pertaining to the Final Rule Establishing Procedures for Special Relief

Issued January 16, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of request for public comments and notice of public discussion.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is soliciting further comments on certain issues related to a draft final rule establishing procedures governing applications for special relief pursuant to its authority under sections 104, 106, and 109 of the Natural Gas Policy Act. The Commission is also establishing procedures for conducting a public discussion of the issues identified in this notice.

DATES: Submission of written comments or of requests to participate in the panel discussion (accompanied by a written comment or a summary of the views to be represented in the panel discussion): February 1, 1980. Panel discussion before the Commission: February 11, 1980.

ADDRESS: Location of panel discussion: Federal Energy Regulatory Commission, Commission Meeting Room, 825 North Capitol Street, NE., Washington, D.C. 20426.

9:30 a.m.

Submission of Written Comments or Requests to Participate in the Panel Discussion: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION:

Susan Tomasky, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 8111, Washington, D.C. 20426, (202) 357-8033.

Blaine Yamagata, Office of Commissioner Hall, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 9006, Washington, D.C. 20426, (202) 357-8353.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission has issued a Notice of Proposed Rulemaking establishing procedures governing applications for special relief.[1] Public comments on this docket were received and, on September 26, 1979, a public hearing was held, as required under section 502(b) of the NGPA.

The proposed regulations would establish higher maximum lawful prices for first sales by natural gas producers subject to sections 104, 106, or 109. The special relief prices would be available to those producers that can demonstrate that the applicable price available under those sections for the well in question will not cover the necessary production costs and that prudently incurred production costs justify rates in excess of the otherwise applicable maximum lawful price under the NGPA.

The Commission is now considering a draft prepared by its staff of the final rule in this docket, attached as

[1] Issued August 14, 1979. 44 Fed. Reg. 49468 (August 23, 1979).

Appendix A. This draft is a staff proposal offered for Commission consideration and published for public information; this draft does not necessarily reflect what will be the final views of the Commission. The Commission emphasizes that the draft final rule contained in Appendix A is subject to change on the basis of the Commission's deliberations on matters in controversy about special relief.

In the course of the Commission's consideration of this draft, and of comments previously submitted on the proposed rule, four issues have emerged, upon which the Commission seeks further public comments, views, and data.

Appendix B to this Notice contains a staff memorandum setting out the four issues upon which the Commission is seeking further public response, and outlining several possible options for resolving them. To assist commenters in responding to these issues, the Commission will briefly summarize here the major questions that it is considering with respect to these four issues.

1. *Possible Limits on Special Relief.*—Under the draft final rule now being considered by the Commission, no limitation would be placed on the amount of the special relief rate that would be available to an applicant, provided that the requested rate could be justified by the formulae specified in the rule, and provided that the actual expenditures were prudently incurred. The draft final rule would delegate to the Director of the Office of Pipeline and Producer Regulation (Director) the authority to approve special relief rate applications pursuant to the Commission's regulation and other administrative instructions to the Director. The Commission is considering whether limits should be permitted on (1) the amount of any special relief rate that would be granted or (2) the discretion of the Director to approve applications for the Commission. The following questions are under deliberation:

—Should the Director be authorized to grant a special relief rate only up to some specified limit, with authority to grant special relief rates above that limit reserved to the Commission.

—If so, what would be an appropriate price level beyond which the Commission would have sole authority to grant special relief?

—Would the public interest be best served by (1) placing no upward constraints on the amount of the special relief rate available to an applicant (assuming that the rate met the prudence and other tests set forth in the proposed rule); or (2) setting some ceiling on the permissible rate?

—If upper limits were to be set on the amount of the special relief rate to be granted by the Commission, what should be the amount of the cap or caps? What public interest considerations should guide the Commission in setting caps, were it to decide to do so?

2. *Election Between a Special Relief Rate or Another NGPA Incentive Price.*—Under the rule as presently drafted, a producer that obtains a special relief rate would not be held to that rate for the life of the project. The producer would be able at any time to seek a determination enabling the producer to collect a higher incentive rate under some other section of Title I of the NGPA. The Commission is considering possible limitations on the authority of an applicant for special relief to switch to other categories.

—Should the Commission limit the opportunity of a producer applying for or collecting a special relief rate to collect an incentive price for which the producer may be eligible under sections 102, 103, 107, or 108 of the NGPA? What legal or policy considerations should guide the Commission in reaching a decision on limiting or not limiting switching of NGPA categories?

—If the Commission should decide to limit switching, how should this be accomplished? Should the Commission require a producer to elect either (1) to receive the highest maximum lawful price or (2) to seek a special relief rate? Alternatively, should the Commission deny special relief to producers of gas that qualifies for a section 104, 106, or

109 price but is also eligible for an incentive price under some other section of the NGPA? Or, should the Commission condition special relief on the existence of a contractual provision that reserves the right of the pipeline to pay the special relief rate for the life of the project? Are there other alternatives the Commission should consider? What are the issues of policy and law involved with a choice among the alternatives?

3. *Review Procedure for Future Applications.*—The draft final rule currently being considered by the Commission would require future applicants for planned investment projects to submit an initial special relief application setting forth a proposed rate computed on the basis of estimated cost data. The final rate would be set not on the basis of the cost estimates but on actual costs prudently incurred. However, the producer would be limited to a rate no higher than the proposed rate (adjusted for general price inflation) even if the producer's actual expenditures were to exceed the original estimates. Several alternative procedures are being considered by the Commission.

—Should the Commission require an applicant to submit for an initial review a proposed rate based on estimated cost and reserve data and thereafter submit for review an application for a final rate based on actual expenditures? If not, what alternative procedure would be preferable? What legal or policy consideration should guide the Commission's choice of a review procedure?

—If the procedure contained in the draft final rule were adopted, what should be the scope of the initial review? The final review?

—If the procedure contained in the draft were not adopted, which, if any, of the options set forth in the attached staff memorandum should be adopted? Are there other alternatives that are preferable?

4. *Rate of Return.*—The draft final rule proposes rule to use a fixed 15 percent rate of return for planned investment projects.

—Should the rate of return associated with a special relief rate be fixed or indexed?

—If a fixed rate is used, what rate of return should be adopted?

—If an indexed rate should be used, should the rate of return be recomputed periodically on the basis of fluctuations in interest rates on long-term Treasury bonds? If not, how should it be adjusted?

Procedures for Comments and Public Discussion

The Commission is seeking written comments on the issues outlined above.

The Commission emphasizes that such comments should *succinctly* set forth the views of a commenter and should be limited to the issues outlined above and discussed more fully in the attached staff memorandum. Comments should be submitted to the Secretary no later than 4:30 p.m., February 1, 1980.

It is expected that the written comments will adequately supplement the record on these issues. However, the Commission has also decided to convene an on-the-record panel discussion before the Commission to permit exploration of these issues with representatives of various points of view about the matters in controversy. This occasion has been selected by the Commission as an opportunity to experiment with the use of a panel discussion technique as a procedure for obtaining public input and insight on issues before the Commission.

Persons wishing to participate in a panel discussion should submit to the Secretary a request to participate no later than 4:30 p.m., February 1, 1980. The request should be accompanied by a brief written summary of the views which would be represented by that person, designating the parties to be represented the amount of time requested for any prepared presentation, and the name and telephone number of the person who would make the presentation. Persons who wish to file written comments and also to participate in the panel discussion may submit the written comments as a

substitute for the summary of views to be expressed in the panel discussion.

The Commission has designated Commissioner George R. Hall to select a panel of representatives of various points of view on these matters. It would assist him if persons wishing to participate would attempt to group themselves on the basis of commonality of interests or provide information that would help in structuring a panel discussion. Commissioner Hall has been given the authority to request the participation of persons whose views may not otherwise be represented but who are not filing written comments. Persons selected to participate will be notified by the Secretary, or by a representative of Commissioner Hall.

Each participant may present a *very* brief prepared statement summarizing his or her views on these issues and will be asked to respond to questions concerning his or her views on the specified issues from the Commission and from other panelists. The Commission emphasizes that it wishes to maximize the time spent in discussion of the issues and plans to limit the time spent on prepared remarks.

By direction of the Commission.

Kenneth F. Plumb.

Secretary.

Appendix A.—*Draft for Discussion*

[Docket No. RM79-67]

Staff Draft of Final Rule

Procedures governing applications for special relief under sections 104, 106 and 109 of the Natural Gas Policy Act of 1978.

I. Introduction

On August 14, 1979, the Commission issued a Notice of Proposed Rulemaking in which the Commission proposed to exercise its authority under the Natural Gas Policy Act of 1978 (NGPA) to prescribe higher maximum lawful prices which are just and reasonable under the Natural Gas Act (NGA) for first sales of natural gas subject to the maximum lawful prices applicable under sections 104, 106 and 109 of the NGPA.[1]

The proposed regulations set forth substantive rules and procedures for extending special relief to a producer of natural gas subject to sections 104, 106 or 109 who can demonstrate that its costs of producing additional gas supplies justify a rate in excess of the applicable maximum lawful price under the NGPA. The final rule embodies essentially the same regulatory scheme as that set forth in the proposed rule, which makes special relief available in two situations. Special relief is available, first, where the operation and maintenance costs of continued production from an existing well cannot be recovered if gas from the well is sold at the applicable maximum lawful price. Also, where additional planned investment is necessary before a producer can continue production from well or begin the development of a reservoir, special relief is available to encourage the additional investment which the producer would not incur if it were held to the applicable maximum lawful price.

The ratemaking mechanism employed in these regulations is designed to assure that the special relief rate comports with the statutory, judicial and administrative standards for determining a rate which is just and reasonable under the Natural Gas Act. The final rule also reflects certain modifications and clarifications which the Commission believes respond to

[1] Paragraph (b)(2) of section 104, paragraph (c) of section 106 and paragraph (b)(2) of section 109 each provide that:

[T]he Commission may, by rule or order, prescribe a maximum lawful price, applicable to any first sale of any natural gas (or category thereof, as determined by the Commission) otherwise subject to the preceding provisions of this section, if such price is—

(1) higher than the maximum lawful price which would otherwise be applicable under such provisions; and

(2) just and reasonable within the meaning of the Natural Gas Act.

many of the concerns expressed in the public comments on the proposed rule.[2]

II. Background

In implementing a program to establish just and reasonable special relief rates under sections 104, 106 and 109 of the NGPA, the history of special relief under the NGA is necessarily instructive. Initially, special relief was a by product of the *Permian Basin Area Rate Proceeding*,[3] in which the establishment of area-wide rates found to be just and reasonable on the basis of average industry costs was challenged as a confiscatory taking of private property without due process of law. The Supreme Court held that no such constitutional infirmity existed where the Commission was prepared to extend relief from the area rate to a producer whose out-of-pocket costs exceeded the revenues to be received under the area rate.[4]

In addition to this "safety valve" type of special relief which permitted the recovery of only out-of-pocket costs,[5] the Commissin during the early 1970's initiated a program to extend special relief to certain categories of gas as an alternative to abandonment and to induce sales of gas which otherwise would be flared. These procedures permitted, on an ad hoc basis, the recovery of costs other than out-of-pocket expenses.[6]

In 1972, the Commission introduced the optional certificate procedure [7] intended to address the claims of producers that the uncertainty surrounding the area ratemaking procedures discouraged planned investment.[8] The procedure authorized a producer to seek certification to sell gas at a just and reasonable rate in excess of the applicable area rate. The optional certificate procedures were upheld, and the court, noting that the Commission had yet to prescribe standards for determining the "reasonableness" of a requested rate, indicated that it would assume that the Commission would promulgate substantive standards which assured that a rate granted under the optional procedures would be just and reasonable under the NGA.[9]

In succeeding years the Commission sought to evolve its substantive standards for optional certificate cases through the evolution of evidentiary guidelines for sorting, in each case, the mix of evidence proffered by the applicant as a basis for determining a just and reasonable rate. In 1974, the Commission indicated that a rate could be determined on a project cost basis.[10]

As applied, this procedure allowed recovery of full costs of a gas supply project plus a 15 percent return.[11]

When in 1978, the Court of Appeals for the D.C. Circuit reviewed the Commission's substantive standard which permitted a total cost recovery, it found that the standard fell short of the requirements of section 4 of the NGA that the rate be "just and reasonable." [12]

[2] At the close of the comment period, twenty-one submissions had been filed. One untimely response has been received. Submissions were received from one state regulatory agency, one pipeline, one association representing forty-two gas distributors, nineteen producers and producer groups, and two Indicated Producer Respondents. The two Indicated Producers represent a total of twenty-eight producers and producer groups.

[3] 34 F.P.C. 159 (1965), *aff'd sub nom.* Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

[4] Permian Basin Area Rate Cases, 390 U.S. 747, 770.

[5] Special relief using an out-of-pocket standard was judicially upheld as an appropriate safety valve for national rates; see Tenneco Oil Co. v. FERC, — F.2d ——, —— (5th Cir. 1978), and was codified at 18 C.F.R. § 2.56(g). In 1975, the Commission authorized special relief on an out-of-pocket basis for older vintage "flowing gas". Opinion No. 749, *aff'd sub nom.*, Tenneco Oil Co. v. FERC, 571 F.2d 834 (5th Cir. 1978) (codified at 18 C.F.R. § 2.56(h)).

[6] Codified at 18 C.F.R. § 2.76–.77.

[7] 18 C.F.R. § 2.75.

[8] Moss v. FPC, 424 U.S. 494, 497 (1976).

[9] *Id.* at ——.

[10] William A. Jenkins, *et al.*, Order Consolidating Proceedings, mimeo at 4 (Docket Nos. CI75–119 and RI75–05) (issued October 3, 1974).

[11] *See, e.g.*, American Natural Gas Production Co., Order Granting Certificate of Public Convenience and Necessity (Docket No. CI77–657) (issued December 5, 1978).

[12] Public Service Comm. of New York v. F.E.R.C., 589 F.2d ——, —— (D.C. Cir. 1978).

In so concluding the court applied three "flexible principles" to be used in testing the reasonableness of a program intended to encourage additional exploration and development:

[T]here must be substantial evidence showing a *demonstrable connection* between the funding in the program under scrutiny and the increased gas supply which it will allegedly produce. There must be some minimum level of coordination of the program under scrutiny with national ratemaking and other programs so that they create no conflicting or unnecessarily duplicating incentives. Lastly, there must be evidence of producers' actual costs so that it can be determined whether the additional funding results in profits too huge to be reconcilable with the legislative command. [Emphasis supplied] [Citations omitted].[13]

Applying these principles, the court struck down the allowance of two categories of costs. First, the Court excluded costs incurred prior to 1972, reasoning that because these old cost were "sunk" before the availability of special relief and thus were incurred without expectation of optional pricing treatment, it could be assumed that rates available under area and nationwide rates were sufficient to induce investment. To allow an additional recovery under subsequently instituted incentive programs would grant a windfall recovery on old expenditures; further, it would bear no connection to production of additional supplies because adequate incentives existed to produce the gas to be sold at a lower rate. Second the Court excluded the cost of lease bonuses based on a detailed analysis which concluded that the full recovery of lease acquisition costs provided no incentives for the production beyond that which arises from an average lease cost recovery implicit within the nationwide rate.[14] The Court, though declining to set substantive standards for the optional pricing program, concluded that the Commission should reconsider its standards in light of this decision, giving "reasoned consideration" to the principles of this case to assure than any special relief or optional rate is "just and reasonable" under the Natural Gas Act.[15]

Contemporaneous to the court's decision in *Public* Service Commission, the Commission indicated its intent to reconsider its policy of permitting full recovery of project cost in optional certificate cases.[16] In that decision, a debate surfaced regarding the wisdom of assuring producers a 15 % return on all costs, including such costs as lease bonuses and exploration costs, which without the guarantee of full cost recovery would ordinarily be undertaken at the producer's risk.[17]

The persistent difficulties which have beset the optional certificate procedures—the problematic development of a substanive standard, the Court's decision in *Public Service Commission*, and the Commission's own doubts regarding the wisdom of its past policy—converge in the context of this rulemaking. Because the Commission's authority under the NGPA to grant special relief is to be judged under a just and reasonable standard, the Commission is compelled to follow the dictates of *Public Service Commission*, in developing standards for cost recovery under the NGPA's provision for special relief. Within the confines of the NGA's just and reasonable standard, however, the Commission's authority to grant special relief is permissive. The Commission has considerable latitude in developing methodologies for cost assessments and in setting limits of eligibility to be applied in evaluating applications for special relief under the NGPA, and must draw upon its experience in administering prior programs as it undertakes this task.

[13] *Id.* at ——.
[14] *Id.* at —.
[15] *Id.* at —.
[16] *American Natural Gas Production Co., et al.*, Order Granting Certificate of Public Convenience and Necessity, *mimeo* at 14 [Docket No. CI77-657] [issued December 5, 1978].
[17] *Id.*, See dissents of Chairman Curtis and Commissioner Hall.

In the proposed rule, the Commission took the position that a special relief rate for gas from a planned investment project should guarantee the recovery of prospective costs, consistent with the directive of the D.C. Circuit that the Commission must show a "*demonstrable connection* between the funding in the [special relief] program under scrutiny and the increased supply it will allegedly produce."[18] This policy was reflected in the provisions of the proposed rule which excluded consideration of costs incurred prior to date of application for pending applications, and prior to the date of staff acceptance of the application for future applications.

Eleven public comments voiced objections to the sunk cost exclusion, citing numerous bases for the contentions that the exclusion would be contrary to the public interest, Commission precedent, the NGA, the NGPA, the Administrative Procedure Act and the United States Constitution.

The Pennzoil Group (Pennzoil) and the Gas Producer Group (Gas Producers) assert first that the sunk cost exclusion is unconstitutional because it voilates the rule of *Permian I*,[19] which, they contend, upheld the constitutionality of area just and reasonable rates on the condition that special relief be made available as a "safety valve" for producers for which sales of gas at the area rate would amount to an unconstitutional taking of private property without due process of law. They argue that in the absence of special relief which permits the recovery of all costs to a producer whose costs exceed the applicable maximum lawful price under the NGPA, a producer could be forced to sell its natural gas a confiscatory rate.

Pennzoil, the Gas Producers, the Indicated Producers, Grace Petroleum Company (Grace Petroleum), Sonat Exploration Company (Sonat) and Terra Resources Inc. (Terra Resources) argued that the provision violates the standards for computing a just and reasonable rate under Commission precedent, the NGA, and, by implication, the NGPA. They note that the Commission, in setting just and reasonable rates, has included the costs of lease acquisition and exploration, and point to the Commission's decision in *American Natural* to demonstrate that this policy has been reaffirmed within the last year.[20]

They assert that the Commission has offered no compelling reasons for changing its policy regarding sunk costs. They conclude that the NGPA explicitly incorporates by reference the whole law governing the determination of just and reasonable rates, including the *Commission* precedent permitting the recovery of sunk costs, and does not suggest that the exclusion of sunk costs is mandated by the language or policy of the NGPA.

Several respondents acknowledged that Commission policy with regard to sunk costs must be responsive to the dictates of *Public Service Commission* which reversed a Commission optional certification awarding the applicants its full costs, including lease acquisition and bonus costs, because those costs were not demonstrably connected to the production of additional natural gas supplies. However, Pennzoil, the Indicated Producers and the Gas Producers submit that the *Public Service Commission* case does not preclude the allowance of sunk costs, but rather established a three part standard by which the Commission should judge all costs claimed to be recoverable under its optional certificate program.[21] They contend that the producer was denied the recovery of sunk costs in that case because it could not offer evidence to meet the three part test, but that in any other case, the rule of *Public Service*

[18] Notice of Proposed Rulemaking, *mimeo* at 13-14.

[19] *See* supra note 3 and accompanying text.

[20] *American Natural Gas Production Co., et al.*; see *supra* note 16.

[21] *Public Service Comm.*, 589 F. 2d at —, *see supra* note — and accompanying text.

Commission does not prohibit a producer from attempting to demonstrate that his sunk costs have a demonstrable connection to the production of increased gas supplies.

In addition, Pennzoil, the Gas Producers, the Indicated Producers and Texas Gas contended that the exclusion of sunk costs will discourage production of marginal properties because incremental costs are inadequate to induce additional investment. The Gas Producers noted that the failure to develop marginal offshore property will result in the lapse of many leases and tremendous waste of initial lease acquisition costs. Kamlock, Inc. commented that the rule discourages development of marginal properties which that producer purchases with the expectation that special relief will be available to recover all costs of acquisition and development. All these respondents conclude, therefore, that the sunk cost exclusion will decrease gas supplies and substantially disadvantage the consuming public.

Pennzoil objected to the proposed cut-off dates for sunk costs, *i.e.*, the date of application for pending applications and the date of staff acceptance of future applications. Pennzoil argued that the date was wholly arbitrary and was chosen only in the interest of administrative convenience. Mesa and the Indicated Producers commented that the exclusion of sunk costs incurred before the initiation of special relief proceedings encouraged premature filings and would result in the granting of special relief on the basis of incomplete data.

The Public Service Commission of the State of New York (New York) voiced support of the cost methodology of the proposed rule because it rejects the full project cost approach of the optional certificate procedures. New York noted that rates based on these costs have never withstood court review so that, even under the old procedures, producers had no reasonable expectation that these costs would continue to be recoverable. Associated Gas Distributors offered no additional comments on this issue, but concurred in the views of New York.

After careful consideration of these comments, the Commission continues to believe that the exclusion of sunk costs is the most appropriate means to encourage producers to undertake additional investments while limiting their recovery to a rate which is just and reasonable under the NGA.

The Commission finds little merit in the argument that there exists a constitutionally protected right to riskless investment in natural gas production. Nor does the *Permian* decision imply that a producer whose overall project costs preclude a rate of return is thereby subject to a confiscatory rate: the "safety valve" procedures, developed in response to *Permian* and upheld by the courts, provided only for out-of-pocket expenses.

Further, contrary to the view of several respondents, the Commission believes the Public Service Commission decision was not merely a reversal on the facts of that case. The Court repeatedly emphasized that the full costs standard failed to meet the just and reasonable standard of the NGA.

Clearly, to observe the limits drawn by that decision, the Commission must refuse to grant relief for expenditures for which the area or nationwide rate, or the NGPA maximum ceiling prices, were sufficient inducements, so that no duplication of incentives results. The Commission must also insure that the relief granted is demonstrably connected to the production of additional supplies.

In addition, the Commission must reconcile its special relief program with the statutory program established under the NGPA, to avoid imposing duplicative costs burden on the consumer. In the *Public Service Commission* case, the D.C. Circuit concluded that by providing full cost recovery in the context of the nationwide rate program consumers bore double the costs of high cost gas by paying an average cost for low cost gas

in addition to paying the full costs of high cost gas.[22] At least with regard to gas priced under section 104 and 106, the same result may obtain: the Congress adopted for these categories of gas the nationwide rate in effect on April 20, 1977, a rate which was determined by the Commission to account for average investment costs for production of gas subject to that rate. The award of full costs to high cost gas similarly levies a double burden on the consumer.

Mindful of these principles, the Commission has scrutinized the types of costs which should be considered in establishing a special relief rate, and has concluded that special relief should be available at the point at which the producer must decide whether to invest in the development of a well. Development costs, clearly, are demonstrably connected to the production of additional supplies of natural gas. And if a producer anticipates that such costs would exceed his expected revenues at the applicable maximum lawful price, the additional investment incentive would be necessary to induce the added investment.

In contrast, expenditures incurred in lease acquisition and exploration are costs which the Commission believes should be undertaken at risk. Comparable sunk costs in onshore production, such as the costs of dry holes and property acquisition, should also be excluded. To the extent that such costs have already been incurred before a special relief rate has been authorized, the applicable prices under the NGPA or the NGA were obviously sufficient inducement for that investment. Further, we are of the view that an adequate incentive for these types of expenditures is assured by adopting the 15 percent rate of return employed in in the 1976 national ratemaking. Studies of industry-wide costs conducted at that time demonstrate that the 15 percent rate of return provides adequate incentive to undertake the costs of lease acquisition and exploration.

The final rule enforces this exclusion through its definition of planned project and the provision which excludes costs incurred prior to the date of application for pending application, or the date of staff acceptance of future applications. The definition limits the availability of special relief for new wells to gas from planned developmental wells or platforms. A producer's application for special relief will be accepted if, at the time of acceptance, his proposed project meets the definition of a planned investment project. The cut-off date effectively implements the Commission's decision regarding recoverable costs by working to exclude costs incurred prior to the point at which a project qualifies as a developmental well or platform.

If a producer has incurred developmental costs prior to the date of acceptance of an application, the cut-off date will work to properly exclude these costs: to permit recovery of those developmental costs, which were undertaken by a producer with only the expectation of receiving the applicable rate under the NGA or NGPA, would result in a impermissible duplication of incentives.

On the effective date of the NGPA, in view of the fact that the NGPA and its implementing regulations superseded inconsistent provisions of the NGA, the Commission ordered that producers with applications pending under the optional certificate procedures were limited to the maximum lawful price applicable under Title I of the NGPA. In that order, the Commission indicated that it would issue a transitional rule to govern the processing of any pending optional procedure case filed before the effective date of the NGPA.[23]

In accordance with that order, the Commission is deleting from its current regulations §§ 2.56a(g), 2.56b(h), 2.75, 2.76 and 2.77. However, the Commission

[22] *Id.* at 37.

[23] Appalachian Exploration and Development, Inc., *et al.*, Order with Respect to Optimal Procedures Cases (Docket Nos. C178-590 *et al.*) (issued December 1, 1978).

believes that a producer who sought relief from the national rates under the optional certificate or other special relief procedures should be afforded an opportunity to demonstrate that its investment, operating, and maintenance costs justify a special relief rate under the NGPA for a well or project which is the subject of a pending application. For these reasons, the proposed rule provided for the processing of pending applications according to the same procedures and substantive standards for determining a just and reasonable rate applicable to future applications.

Several respondents objected to the applicability of this rule to pending applications, arguing that to do so constitutes impermissible retroactive rulemaking. In particular, the Indicated Producers, Pennzoil and the Gas Producers have argued that the Commission must judge pending applications on the basis of evidence of full project costs, and must provide an opportunity for evidentiary hearings before an impartial trier of fact as would have been available under the optional certificate procedures.

The Commission is very much aware of its responsibility to protect antecedent rights which have vested prior to the promulgation of a new regulation. For a number of reasons, however, the Commission must conclude that pending applicants have no vested rights to pursue their applications under the old procedures.

As noted above, the Commission's authority under the NGA to provide special relief was superseded by a permissive grant of authority to extend special relief to certain categories of gas under the NGPA. Thus, the NGPA did not extend the life of special relief and optional pricing, but merely invited the Commission to implement similar programs under the NGPA. Until the Commission exercises its new authority to extend special relief, prior applications are "pending" under the Commission's regulations but not under the NGPA.

In addition, the Commission in implementing its new procedures must follow the statutory mandate that the special relief rate be just and reasonable under the NGA. In light of the *Public Service Commission* case, the Commission has no authority to award a full cost recovery in any special relief case. Rather, the Commission is required in all cases to allow only those costs which are demonstrably connected to the production of additional gas supplies.

For purposes of processing pending applications for planned investment projects, the rule permits applicants to consider any costs incurred subsequent to the filing of an application for special relief under prior procedures. The Commission will assume that at the time an application was filed, the producer had reached a point in the investment project where special relief was necessary to induce further investments.

The Commission has also considered the arguments of some respondents that producers with pending applications are entitled to full evidentiary hearings in determining their special relief rate. While such a hearing may have been the appropriate forum for determining a rate on the basis of full project costs, there would be little advantage to an evidentiary hearing on facts alleged in support of an application for special relief in line with the substantive standard which permits only the recovery of incremental costs, by application of mechanical formulae and methods. For the most part, we are persuaded that the procedural changes do not inure to the prejudice of a prior applicant because the costs to which he is entitled can be fairly computed under the new rules.

The Commission acknowledges that it imposes some additional burden in requiring that pending applications be supplemented to conform to these procedures. To the extent that conforming filings are necessary to permit the Commission to evaluate the applications under the substantive standard set forth in these rules, that burden is unavoidable. However, because in many instances the necessary information is before the

Commission, an applicant has the opportunity to proceed on his pending application by giving notice of his intent to do so, and stating that he believes his application to be in compliance with these procedures. Once an applicant has done so, the burden is on the Staff to inform him of any deficiencies in his application.

In the case of pending applications for wells for which there is no planned investment, the procedures for staff review set forth in the proposed rule involve only a simple determination that the applicant is eligible for special relief for the well or project, and that the costs to be recovered are within the substantive standards set forth in this rule. Applicants for planned projects which qualify as small projects are subject only to one staff review to determine their eligibility under the special provisions for small projects. The Commission continues to believe that these procedures represent the most expeditious means for determining a special relief rate for pending applicants under the new procedures.

We are persuaded, however, that the provisions for two-step review of pending applications for planned investment projects, is of little advantage in the case of pending applications. Such projects may be at varying stages of completion so that the intended benefit of the initial review—the scrutiny of costs in advance of their expenditure—would never obtain. For this reason, the Commission will require that a producer with a pending application for a planned investment project be subject to one staff review conducted at the completion of a project.

As set forth in the proposed rule, the special relief rate for gas produced from a planned investment project would be the rate which it is expected will provide the producer with a fifteen percent true yield on costs which are prudently incurred and which are in line with comparable industry expenditures. Costs would be determined by use of a discounted cash flow methodology (DCF), and the resulting rate would be effective over the life of the project, and escalated at a rate of seven percent compounded for each subsequent year.

For wells for which there is no planned investment the proposed rule set forth a method for computing a flat rate intended to permit the recovery of out-of-pocket operating and maintenance expenses reasonably assigned or allocated to gas produced from the well. The flat rate would be computed on the basis of out-of-pocket expenses estimated over the life of the project, or estimated for the first year and compounded at a rate of seven percent per year for each subsequent year. Comments were specifically solicited on the possible use of a DCF to assure that producers receive their current costs.

Comments on the rate computation method addressed a wide variety of issues. Several respondents took issue with the proposed 15 percent rate of return for planned investment products, arguing for a variety of reasons that it was too low to provide an adequate incentive for a major investment venture, because it is based on the 1978 ratemaking, and therefore fails to account for the continued rise in interest rates since that time. In addition, the Indicated Producers have argued that the appropriate rate for national ratemaking, which is based on average industry costs, is not relevant to an individual applicant for special relief.

Several respondents argued that the invariable application of a 15 percent rate is inappropriate in light of the varying capital structure of each applicant for special relief. Petro-Lewis suggested that the proposed rule be amended to guarantee a 15 percent rate of return, and the Gas Producer Group proposed that the 15% rate be adjusted monthly in line with the monthly inflation adjustments applicable to maximum ceiling prices under Title I.

New York noted that it is not uncommon for a natural gas producer, particularly one which owns an affiliate pipeline, to have a capital structure heavily weighted toward debt. The result, they argue, is that a 15 percent

overall return can result in a windfall, *i.e.*, an unreasonably high return on equity. To avoid this problem, New York suggests that the Commission grant a special relief rate based on a 17 percent predicted return on equity.

The Indicated Producers found the DCF to be inadequate in several respects. They claim that the example of its application provided in the notice of proposed rulemaking was ill-defined and required further explanation. Sonat requested that the Commission use a statutory tax rate in the DCF without a reduction for percentage depletion and investment tax credit, rather than the marginal effective tax rate described in the proposed rule, arguing that the rate as proposed discriminates against a young company whose revenues are inconsiderable. Texas Gas and the Indicated Producers urge the Commission to delete the requirement that costs be prudently incurred. They believe that there exist no guidelines for its application in the context of a planned investment project.

Regarding the rate for wells for which there is no planned investment, most comments were directed to the failure of the proposed rule to allow for a return on expenditures for wells for which there is no planned investment, contending that no producer will continue to operate a well with no opportunity to realize a profit. It was urged the Commission permit a 15 percent rate of return.

Texas Gas Exploration Co. expressed concern that the 7 percent inflation factor was inadequate to meet the demands of current economic circumstances.

The use of the "tilt" for wells for which there is no planned investment was endorsed by Kamlock, Inc. New York, pointed out that a "tilted" rate based on a DCF analysis such as that applied to planned investment projects would provide recovery of "current" operating costs. They contended, therefore, that the recovery of "current costs" on top of the 7 percent inflation adjustment would represent a double recovery.

In response to the Commission's request for comments on alternative methods of rate determination, Natural Resources urged the Commission to permit applicants to use other methods of cost assessments. They claimed that the DCF is misleading when applied to remedial well work where expenditures, work, and receipt of income are spread out over time. They requested that the Commission use an economic analysis which puts more emphasis on payout time mechanism described in the preamble as an alternative to the proposed flat rate. Kamlock, Inc. endorsed the use of the "tilt" but did not give reasons for its position.

Although the Commission received little response to its request for comments on alternative methods of computation, we are of the view that a "tilted" rate, such as that outlined in the preamble in Notice of Proposed Rulemaking, is preferable to a level rate, such as that set forth in the proposed regulation. The level rate method of computation is designed to yield a constant rate over the life of the project increased by a flat inflation rate for operating expenses applied annually. The effect of this method is that during the early phases of the project's production life, when production is higher, the producer is receiving what amounts to an incentive rate in the form of an excess recovery of operating expenses. As production declines this recovery decreases, so that at some time in the production life the producer faces a negative cash flow situation. In theory, the excess recovery during the early phases of production is intended to compensate for the lesser revenues at a later time. However, it is more likely that when a producer reaches the point of lower revenues he will seek either abandonment or additional special relief, arguing that the well is in a confiscatory state.

For planned investment projects, the "tilted" rate is determined by breaking the rate computation into two components. The first component is comprised of the recovery of investments and the return on

investment per unit of production and the Federal income allowance, determined by use of the DCF. The Federal income tax allowance will be the marginal effective tax rate for the project, which will be the statutory rate decreased by the amount of percentage depletion and investment tax credit.[34] It will remain constant over the life of the project.

The second component provides for a recovery of operating expenses per unit of production computed monthly on the basis of actual deliveries, increased by the amount of the monthly inflation adjustment factor published quarterly by the Commission. The effect of the tilted rate is to provide the same return on investment as the level rate, but to distribute the recovery of operating expenses over the life of the project thereby averting the possibility implicit in the flat rate method that the producer will recover an excess in the early stage of production and reach the point of negative cash flow at a later time. An example of the application of this rule to a hypothetical project is appended to these regulations.

Estimated operating expenses may include allowance for taxes, such as *ad valorem* property tax, other than state income taxes, Federal income tax (which is accounted for in DCF) and State severances as defined in subpart K of the Commission's regulations. This provision would not preclude a producer from seeking adjustments for state severance taxes under subpart K.

The proposed rule adopts the 15% rate of return on the basis of the most recently established data, amassed in connection with the 1976 area ratemaking. This rate has survived judicial review.

[An analysis of the use of the 15 percent rate of return will be supplied by the Office of Regulatory Analysis]

The out-of-pocket rate for wells for which there is no planned investment would be determined in the same way in which the operating expense component is computed for planned investment projects, based on actual production. The Commission agrees that the 7 percent annual inflation adjustment may be inadequate and thus has incorporated into its formula for determining the out-of-pocket rate the monthly GNP deflator published by the Commission. This formula would yield a return only of the current expenses.

The Commission further believes that the decision to use the "tilt" requires us to reconsider our decision to provide no incentive allowance in the rate for wells for which there is no planned investment. As noted above, the use of a flat rate to compute the recovery of out-of-pocket expenses would permit a rate in the early stages of production somewhat in excess of actual expenses; this excess would decline in concert with the decline in rate of production. When the producer reached the point of negative cash flow he could seek additional special relief, claiming quite accurately that his incremental costs exceeded his revenues under his current rate. However, the "tilted" rate would assure the continued recovery of all approved expenses, but would provide no excess. Therefore, to provide a reasonable inducement to keep such wells in operation, the Commission will permit a 5 percent incentive allowance after an allowance for Federal income tax. We have concluded that a five percent allowance is sufficient to encourage continued production based on the analysis which is attached at an appendix to this rule.

The Commission sees little wisdom in the suggestion the producers be relieved of the requirement that only costs which are prudently incurred may be considered in computing the special relief rate for planned investment projects for wells for which there is no planned investment. This standard provides the Commission with some assurance that the approved special

[34] We have retained the exclusion of investment tax credits from the Federal income tax allowance; its inclusion would build an additional incentive into the tax rate which duplicates the incentive created by the investment tax credits.

relief rate will be a just and reasonable one. It is certainly true that this standard cannot be mechanistically applied in the same manner in which Staff can apply the rate computation formula. However, the regulation does provide some guideline in that costs will be judged to be prudent if they are in line with comparable industry expenditures for similar equipment or services. The right of Commission review, which guarantees an applicant an opportunity for the Commission to review any disputed issue of fact and offers the possibility of remand for hearing in appropriate circumstances, assures the Commission that this essential standard can be impartially administered.

The comments also contained a number of requests for clarification and suggestions for modification of various other aspects of the proposed rule. Except for the change in the rate determination methodology, the regulatory scheme set forth in the proposed rule has not been substantially modified. However, as will be noted subsequently, the Commission has modified and clarified certain aspects of the regulation in response to the public comments.

III. Section-by-Section Analysis

§ 271.1001 Applicability

This section makes special relief available to a producer of natural gas (other than Prudhoe Bay unit Alaska gas) subject to a maximum lawful price under sections 104, 106, or 109 of the NGPA. These sections apply respectively to gas committed or dedicated to interestate commerce on November 8, 1978, gas sold under rollover contracts, and gas not covered by any other maximum lawful price under Title I of the NGPA. In accordance with section 101(b)(5) of the NGPA (which provides that gas qualifying for more than one maximum lawful price or "any exemption from such a price" shall qualify for the highest applicable price), natural gas which is subject to section 104, 106, or 109 is eligible for special relief even if it qualifies for a maximum lawful price under some other section of Title I.

The Commission wishes to make clear that the exclusion of Alaskan natural gas from this rulemaking was not intended to announce a policy that special relief would never be available to producers of Prudhoe Bay Unit Alaskan natural gas. Rather, the Commission finds that special relief for Prudhoe Bay natural gas should be made available through separate procedures developed in consideration of the special circumstances surrounding the production of that type of natural gas.

In the notice of proposed rulemaking the Commission solicited comments on whether it may or should extend the rulemaking to gas priced under sections 102, 103, 105, and 108 of the NGPA, by exercise of its authority to set higher prices for high cost gas under section 107, or its authority to adjust any maximum lawful price to allow for production related costs under section 110 of the NGPA.

Several respondents offered persuasive reasons for extending special relief to other categories of gas, most particularly with reference to gas priced under section 105. They point out that a producer of gas priced under section 105 who is locked into a fixed rate contract may reach a level of marginal production before the primary term of the fixed rate contract ends, reducing the well to a confiscatory state. Also, they argue, a producer would never initiate supply enhancement projects for such a well, sacrificing the benefit to consumers of added production from that well.

It was also suggested that special relief be extended through section 107 on an incentive rather than a cost basis. They pointed to language in the Joint Explanatory Statement of the Conference Committee accompanying the NGPA Conference Report (Joint Statement), which suggests that section 107 may not be used to impose the cost-based rate methodology employed in the proposed rule. The Joint Statement explicitly provides that ceiling prices established by the Commission under section 107(c)(5) "are not intended to be

cost-based in nature, and do not require cost justification." [25]

That same language in the Joint Statement leads the Commission to conclude that section 107 is a wholly inhospitable vehicle for cost-based special relief. Section 107 contemplates the establishment of a maximum price applicable to a generic category of high cost gas rather than a rate applicable to gas produced from a specific project.

Similarly, extension of special relief through section 110 presents certain substantive and procedural difficulties. To some extent the costs to be recovered under section 110 and under special relief may coincide. Section 110, however, permits the recovery of a narrower range of costs,[26] and provides for Commission approval of the pass-through of those costs at the point of sale. Under procedures for special relief, costs must be assessed and submitted to the Commission in the form of the initial application prior to expenditure of funds.

For these reasons, the Commission is not satisfied that the procedures set forth in these rules are the appropriate means by which to offer special relief to other categories of natural gas, and we will pursue such action in a separate rulemaking.

§ 271.1002 Definitions

This section defines certain terms for purposes of the regulation governing procedures for special relief.

Under this rule, special relief is limited to a "first seller" which, under paragraph (a) of this section is defined to exclude reseller as defined in the Commission's regulations.[27] These procedures, designed to compensate for production costs, are not ordinarily adaptable to the types of expenditures incurred by a reseller, and in no case would a factor such as production volumes, essential to computation of a special relief rate, be relevant to a reseller. A reseller would of course have the opportunity to seek an adjustment for production related costs under section 110 of the NGPA.

To abate the confusion which appears to have arisen from the reseller exclusion, we wish to make clear that in no way do we intend to disturb the regulatory mechanism of §270.202(a)(2)(i) of the Commission's regulations, which provides that the maximum lawful price which governs the seller's price is also the reseller's maximum lawful price.

Paragraph (b) defines a planned investment project as a planned onshore well and related production facilities, a planned offshore development well and related production facilities, offshore platforms, wells drilled on the platforms, and related productions facilities, or planned production enhancement work on a previously producing well. Paragraph (c) defines "related production facilities" as the equipment and facilities of the first seller which connect the wellhead to the purchaser's facilities. Production enhancement work is also defined.

Three respondents took issue with the Commission's proposal to define "planned investment project" as a "well or platform". The effect of this definition, they correctly point out, is to require a producer to justify his costs for each well or platform for which he seeks special relief.

Terra Resources and the Indicated Producers expressed concern that the rule is particularly disadvantageous to offshore producers whose large "up front costs" would not be recoverable except to the limited extent they could be attached to a producing well. Exploratory dry hole costs would, by definition, be excluded.

The Indicated Producers questioned the Commissioner's assumption that the

[25] S. Rep. No. 1752, 95 Cong., 2d Sess. 88 (1978).

[26] i.e., State severance taxes and specifically designated production related costs. NGPA, section 110(a)(1)–(2).

[27] § 270.202(e)(1)(2) provides that a reseller means the seller in a sale of natural gas, all or a portion of which was both purchased and resold in transactions which are first sales as defined in the NGPA.

data necessary to support applications for each well or platform would be readily accessible to the applicant. They claim that companies maintain records on an entire "project" rather than on the individual well, and thus that the Commission should continue its practice in optional procedure cases where the parameters of a "project" would be drawn on a case-by-case basis, with reference to the applicant's evidence as to what constitutes a project.

The New York Public Service Commission suggested that the requirements for "well-by-well" submissions was a response to an abuse which plagued special relief and optional pricing proceedings under the old rules, *i.e.*, the prarctice of seeking relief for larger numbers of wells, grouped together under the lable of "one project," when in fact only some of the wells in the grouping had costs which would justify a special relief rate.

The Commission has not modified its definition of planned investment project to permit the consideration of applications which encompass work on more than one well. It is crucial to the implementation of other provisions of the proposed regulations which limits cost recovery to incremental costs, because is assures the submission of data necessary to assess costs on this basis. We will permit producers to submit one application for a special relief rate for gas produced as a result of production enhancement work, such as installation of a compressor or a salt water disposal system, which serves a group of wells.

While it is true that offshore production involves large "up front costs", one of the largest of these costs—platform construction—can be recovered under these rules. While exploratory dry hole costs may not be recovered, it must be remembered that special relief is not intended to guarantee a producer against all risks but only to provide a rate which insures the availability of additional supplies which might not otherwise be produced—a purpose which is adequately served by the allowance of incremental costs.

Natural Resources has commented that the definition of "related production facilities" is too restrictive because it fails to include "production related facilities such as compressors, separators and other related equipment".

However, the Commission has chosen to employ a broad, generic definition to avoid identifying particular pieces of equipment, an approach which risks the inadvertent exclusion of equipment which might properly be considered a planned investment project. Compressors, dehydrators, and other related equipment could fall within this general difinition.

§ *271.1003 Eligibility*

This section states that a first seller may apply for a special relief rate for natural gas produced from a planned investment project or from a well for which there is no planned investment, if, at the time the application is filed, the first seller has contractural authorization stated in cents per MMBtu to charge and collect the proposed rate.

Three respondents urged the Commission to permit parties to amend their contracts to provide authority to collect the special relief rate after the rate has been determined. Texas Oil & Gas Corporation suggested that the contractural authority not be required to be stated in terms of cents per MMBtu, pointing out that a price escalator clause which authorizes the collection of any rate granted the seller by the Commission in a proceeding for special relief would not meet the requirements of this section.

The Indicated Producers argued that the Commission's authority to determine an applicant's eligibility for special relief is no greater than its authority to determine a well's eligibility to receive a maximum lawful price: the determination that a well is eligible to receive an applicable maximum lawful price does not depend upon the existence of contractural authorization to charge that maximum lawful price, although the producer must have contractural authorization before he can collect the price from a purchaser. They

also claim that because, at least in the case of offshore gas, the purchase and sale is often negotiated just prior to the commencement of production, a producer could file only after all major capital expenditures have been made thereby suffering the exclusion of all costs previously incurred. They argue that a producer would be forced either to abandon a project, to delay application and thereby suffer a return on a smaller amount of his capital costs, or to sign a contract committing him to undertake a planned investment which he later may discover, on the basis of information acquired during exploration, to be imprudent.

The Commission is not persuaded by these arguments. Under the proposed rule, the special relief rate is computed on a cost basis without reference to a ceiling price; so long as a producer can show that the costs incurred are prospective and prudent a rate will be granted to account for those costs, even where the ultimate cost of production exceeds the value to the public of the additional supplies.[28]

The Commission believes that this result is best avoided by reliance on the mechanisms of the natural gas market. A reasonable upper limit on the special relief rate would be effected by operation of the process of contract negotiation, in which it is assumed that a purchaser, informed by a knowledge of market circumstances and the dictates of prudent business judgment, would not contract for an unreasonably high price.

The Commission further believes that this mechanism is most effective when parties must come to terms on an appropriate fixed rate. In this way, we are assured that pipelines, as well as producers, will scrutinize the investment costs of the proposed project before negotiating a contract, we expect that the resulting price will be tempered by such a scrutiny. To permit subsequent amendment of contracts to meet this requirement negates this intended affect of the provision.

The Indicated Producers have quite correctly asserted that in many cases the pipelines will not negotiate contracts before exploration is undertaken and some assessment of reserves and production costs is available. This is particularly true, for example, where a pipeline may have to construct a lateral extension to receive new supplies, requiring Commission certification based in part on data pertaining to reserves. This presents a problem, however, only when a producer is seeking to circumvent the exclusion of sunk costs by applying for special relief well in advance of the time when expenditures are actually related to the development of additional supplies. Thus, the effect of the contractual authorization provision is not to coerce the premature negoation of contracts but to avoid the premature application for special relief by assuring that only actual costs related to enhanced production are covered, and that other initial costs, excluded because they precede the date of application, are undertaken at the producer's risk.

Also, as a practical matter, much of the gas eligible for special relief under this program is priced under section 104 or 106, which by definition is already committed to interstate commerce, in many cases under existing contracts. Although these contracts may not contain the specific authorization required by these regulations, parties to these contracts would not be precluded from amending those contracts in advance of application to comply with Commission authorization.

§ 271.1004 Special Relief Rate

This section sets out the method for computing the special rate for planned investment projects and for wells for which there is planned investment.

For planned investment projects other than small projects, the rate is

[28] For this reason, New York has urged the Commission to adopt the section 102 maximum lawful price as an absolute ceiling on special relief rates, either because it is consistent with the purpose of the NGPA to keep prices below the section 102 price until 1985, or because it is in the public interest.

determined by adding two components.[29] The first component, which is constant over the life of the project, is the rate under which it is determined that an applicant will earn a 15 percent true yield on its investment, after allowance for Federal income tax, to be computed using the discounted cash flow method (DCF). In computing investment costs under the DCF, for the reasons set forth above, the Commission will consider only those costs incurred after staff acceptance of an initial application, except that in the case of pending applications, costs shall be considered which were incurred subsequent to the date the pending application was filed under the prior procedures. The second component of the rate for planned investment projects is computed monthly on the basis of fluctutations in production volumes and inflation. To assist applicants in making the calculations under this section, an example is attached as an Appendix to the final rule.

As noted above, the rate for wells for which there is no planned investment will be computed in the same manner in which the operating expense component for planned investment projects are calculated.

In determining the final rate in all cases, the Commission will consider only those costs which are prudently incurred.

§ 271.1005 Application

This section sets out the procedures for submission of new applications for special relief and for providing the opportunity for applicants for special relief or optional pricing under existing Commission regulations to proceed under the new rule. Future applicants for special relief for planned investment projects must also file supplemental applications within 60 days of completing a project, reporting their costs actually incurred during the course of the project. Proceedings for special relief are considered to be commenced when an initial application for each well or project is filed and notice to purchasers is served.

Persons whose applications are now pending before the Commission must give notice of intent to go forward with the application within 30 days of the issuance of these rules in final form, or the application will be deemed withdrawn. At the same time, the applicant must submit a statement, made under oath, that it believes that these procedures are applicable to natural gas to be produced from the project or well under the provisions of § 271.1001, and that the applicant is a first seller, as defined in § 271.1002. Such applicants must also conform their pending applications to the requirements of the new regulation.

§ 271.1006 Intervention

This section authorizes intervention pursuant to § 1.8 of the Commission's regulations within 15 days of service of the application, or in the case of a person who has not been served, within 15 days of publication in the **Federal Register**. Authority is given to Staff to grant or deny petitions to intervene.

New York points out that the rule as drafted is administratively inconvenient for intervenors who usually get notice through service or from the Commission's Office of Public Information, but who do not refer to the **Federal Register**. They therefore request that the Commission issue public notice specifying a date certain by which petitions for intervention must be filed.

Although the Commission does not wish to create obstacles for intervenors, New York's request ignores the interests of potential intervenors whose resources are such that they must rely on the **Federal Register** for notice of Commission action. The provision will be retained as proposed to avoid prejudice to an intervenor that could arise by unexpected administrative delays between the date of Commission issuance of notice and its publication in the **Federal Register**.

[29] See supra, note — and accompanying text.

§ 271.1007 Review by Staff

A. *The regulation.* Section 271.1007 sets forth procedures for Commission consideration of pending and future applications for special relief. A future application for special relief for a planned investment project, other than a small project, is first reviewed by the staff of OPPR, which "may" notify the applicant that it has taken one of three types of action: that staff finds the filing deficient, and is requesting additional information; that the application is rejected for failure to provide the requested additional information, or because the gas does not meet the eligibility requirements of § 271.1003, or because the proposed rate has not been computed in accordance with the provisions of § 271.1004; or, it may accept the application upon determining that applicant is entitled to special relief.

The effect of acceptance of an application is to authorize the applicant to "include in its supplemental application . . . those investments and expenses permitted under § 271.1004 which were made or incurred for the project subsequent to such acceptance, but shall not imply approval of any expenditures included in the application."

Within 60 days of the completion of a planned investment project (other than a project which is the subject of a pending application), an applicant will have submitted his supplemental application pursuant to § 271.1005 setting forth his actual costs. Under § 271.1007, the staff will review this supplemental application and may either request additional information, reject the application on any of the grounds for which initial applications may be rejected, or issue a Staff report recommending approval of a specified rate, stating the basis for the rate and any disputes with the applicant on factual issues. All persons entitled to service of the initial or supplemental applications are entitled to service of the staff report.

Finally, the staff must consider all filings made in connection with an application for special relief. The staff is accorded authority to investigate or audit statements in the application, to solicit or accept submission for intervenors and to conduct conferences under procedures the staff considers to be "most expeditious." All persons entitled to service may be present at such conferences.

Applicants for special relief for a planned investment project which is the subject of a pending application or for wells for which there is no planned investment are not required to proceed through the two step application process. Their initial applications are treated in the same manner as supplemental applications for planned investment projects.

Special provision is also made for a producer proposing to undertake a small project. The producer may receive its proposed rate, without a cost-based analysis if it meets three criteria. First, the total proposed rate for the sale of gas from the project may be no more than the applicable rate for large producer sales as established under section 106(a) of the NGPA, for gas priced under rollover contracts. The Commission has adopted this maximum rate in place of the proposed rate of 60 cents per mcf in response to persuasive arguments raised in public comments that the failure to provide periodic adjustments in the approved rate would discourage potential applicants from availing themselves of the simplified procedures.

Second, the rule requires that the enhancement work to be undertaken in a small project must result in estimated additional revenues to the applicant of less than 100,000 times that rate. This also reflects a change from the proposed rule which limited the amount of additional revenues to $60,000. The Commission is persuaded by the arguments of respondents that the limit to be imposed under the proposed rule would exclude a large number of producers whose expected revenues would be inadequate to justify pursuing an application for special relief under the procedures applicable to large projects.

The Commission has retained the third proposed requirement, that the proposed investment in the project exceed 25 percent of the estimated additional revenues to be generated by the project.

A variety of other issues were raised in public comments which require clarification. New York and the Indicated Producers note that although the acceptance of an initial application authorizes the applicant to file his supplemental application for the proposed rate, it is not clear whether the Commission thereby intends to preclude the approval of a rate based on actual costs which are in excess of the cost estimates underlying the proposed rate but which, nevertheless, are prudently incurred.

It was the Commission's intent to encourage producers to scrutinize carefully the project's costs before its undertaking by providing that an applicant may not receive a rate in excess of the proposed rate. The final rule has been amended to more clearly effectuate this intent.

The Commission was also requested to address the question of whether an applicant would be permitted to apply for an increased special relief rate at a later time. Under prior procedures, an applicant with an optional rate certificate would be held to the certificated rate for the life of the project, although no similar limitation was imposed on recipients of other forms of special relief.

Where a producer of gas already priced under a special relief rate wishes to undertake additional planned investment (for example production enhancement work) he may of course seek special relief if his project falls within the definition of a planned investment project. With regard to out-of-pocket expenses, the use of the "tilted" rate, which insures that an applicant will recover current expenses for the life of the project or well, appears to alleviate the problem of additional special relief. If, however, a producer who is subject to a special relief rate can justify a need for a higher rate to cover out-of-pocket expenses, he is not precluded from seeking additional special relief.

§ 271.1008 Determination of Rate by the Director of OPPR; and § 271.1009 Commission Review

Section 271.1008 provides that the Director of OPPR or his designee must determine the special relief rate or recommend other appropriate action to the Commission. The Director's decision is final thirty days after publication in the **Federal Register**, unless during that period appeal is taken to the Commission or the Commission directs that the order be submitted to it for review.

Section 271.1009 sets forth the procedures for Commission review. Any person adversely affected by staff acceptance or rejection of an initial application, staff action on a petition to intervene, or the Director's determination of a special relief rate, may seek Commission review. The staff, on its own motion, may seek review. Commission review shall be on the record; the Commission shall provide such opportunity for additional submissions including, hearings, as it deems necessary.

For the most part, comments on these sections concerned the delegation of decision-making authority to staff. The Indicated Producers suggested that this approach, which involves essentially a mechanistic application by staff of a formula, was appropriate for a vast number of cases; they endorse the Commission's decision to make such procedures available to applicants who choose to use them. They contend, however, that in many cases the facts are too complicated and the interests of the parties too considerable to deny a producer the right to have important issues of fact, such as "cost estimates", "prudence" or "gas reservoirs," decided by an impartial trier of fact. Pennzoil offered a similar argument with regard to pending applications.

Sonat and Texas Gas requested that the Commission establish mandatory time frames for each phase of the procedures. The same logic that persuades the Commission that

evidentiary hearings are unnecessary for pending applicants gives rise to our decision that the procedures for staff review are appropriate. The computation of a rate based on incremental costs does not involve the variety of complicated or factfinding issues which the Commission believed warranted an evidentiary hearing under the prior procedure.

Contrary to the claims of the Indicated Prodcucers, the Staff ordinarily will not inquire into factual assertions of producers about "cost estimates" or "production", so that the only recurring main issue of fact to be decided by the staff is the issue of the prudence of the costs incured. In addition, a full review by the Commission is available on the record which must contain evidence of all factural disputes, thereby according the applicant all process which is due. For these reasons, we believe that these procedures accomplish a fair and full consideration of all relevant data, at the same time they reduce the possibility of unnecessary administrative delay.

The Commission understands that a producer who is entitled to special relief would prefer that the Commission act on his application by a date certain. However, until the staff and the Director acquire some experience in the implementation of these regulations, any attempt to establish a time frame for review and rate determination would be wholly arbitrary. Because the provisions for retroactive collection substantially cure the injury to the applicant arising from regulatory delays, the Commission will not establish time frames or staff review or for the Director's rate determination decision.

§ *271.1010 Retroactive Collection*

In the case of future applications for special relief for wells for which there is no planned investment, the applicant may charge and collect the special relief rate for sales of gas from the well beginning on the date the application for special relief was filed. Applicants for special relief for planned investment projects, including small projects, may collect the special relief rate retroactively beginning on the date deliveries from the project were commenced.

In the case of applications now pending filed under § 2.75, the seller may collect the special relief rate retroactively beginning on either the date that notice of intent to proceed with the application is filed or the date nine months following commencement of deliveries under the contract to which such special relief rate applies, whichever is earlier. For pending applications filed under other prior procedures, collections may begin on the date notice of intent to proceed with the application is filed in the case of a well for which there is no planned investment, and, in the case of planned investment projects, the later of the date notice of intent to proceed was filed or the date deliveries commenced.

Mesa Petroleum argued that it is discriminatory to draw upon the optional pricing procedures to impose a nine month limit on retroactive collection, while denying applicants who filed under those procedures the substantive and procedural advantages available under the old rules.

However, the Commission believes that this time limitation does not prejudice parties with pending applications who, when they filed unted § 2.75, had no expectation of collecting the optional rate prior to nine months after the date deliveries commence under the contract to which such special relief rate applies. For this reason the provision is retained.

§ *271.1011 Filing Requirements*

A. *The regulation.* This section sets out the various filing requirements applicable to planned investment projects, small projects, and wells for which there is no planned investment.

IV. Effective Date

The Commission is aware that the lengthy delay in the implementation of this rule has left many applications pending since the effective date of the NGPA. The Commission therefore finds

good cause for making these rules effective immediately.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.*; Natural Gas Policy Act of 1978, P.L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. § 7107 *et seq.*; Exec. Order No. 12009, 42 Fed. Reg. 46267)

In consideration of the foregoing, Parts 2 and 271 of Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By direction of the Commission.

Secretary.

§§ 2.56, 2.75, 2.76 and 2.77 [Amended]

1. Part 2 is amended in the Table of Contents where appropriate and in the text of the regulations by deleting §§ 2.56a(g), 2.56b(h), 2.75, 2.76, and 2.77. Paragraphs (h) through (p) of § 2.56a are redesignated as paragraphs (g) through (o). Paragraphs (i) through (n) of § 2.56b are redesignated as paragraphs (h) through (m).

§§ 271.1001 through 271.1011, Subpart J [Added]

2. Part 271 is amended in the Table of Contents by deleting "Subpart J—[Reserved]" and substituting the following in lieu thereof:

Subpart J—Special Relief

Sec
271.1001 Applicability.
271.1002 Definitions.
271.1003 Eligibility.
271.1004 Special relief rate.
271.1005 Application.
271.1006 Intervention.
271.1007 Review by Staff.
271.1008 Determination by the Director of the Office of Pipeline and Producer Regulation.
271.1009 Appeals to the Commission.
271.1010 Retroactive collection.
271.1011 Filing requirements.

3. Part 271 is further amended in the text of the regulations by deleting "Subpart J—(Reserved)" and substituting the following in lieu thereof:

Subpart J—Special Relief

§ 271.1001 Applicability.

This subpart sets forth the conditions under which special relief may be obtained for any natural gas which is subject to a maximum lawful price under section 104 or 106, (whether or not such gas qualifies under any other section of the NGPA) or 109 of the NGPA except that this subpart does not apply to natural gas produced from the Prudhoe Bay unit of Alaska and transported through the natural gas transportation system approved under the Alaskan Natural Gas Transportation Act of 1976.

§ 271.1002 Definitions.

For purposes of this subpart:

(a) "Planned investment project" means:

(1) a planned onshore well and related production facilities;

(2) a planned offshore development well and related production facilities;

(3) a planned offshore platform, wells drilled thereon and related production facilities; or

(4) planned production enhancement work on a previously producing well or;

(5) planned production enhancement work serving a group of wells.

(b) "Related production facilities" means the equipment and facilities of the first seller which connect the wellhead to the purchaser's facilities.

(c) "Production enhancement work" means work in the nature of reconditioning, workover, deeper drilling, replacing or adding major equipment or related production facilities, or any other additional work necessary to prevent the loss of gas production or reserves.

(d) "First seller" means a seller in a first sale as defined in paragraph 20 of section 2 of the Natural Gas Policy Act, except that it shall exclude a reseller as defined in § 270.202(e)(2) of this chapter.

§ 271.1003 Eligibility.

(a) A first seller may apply for a special relief rate under this subpart for natural gas produced from:

(1) a planned investment project as defined in paragraph (a) of § 271.1002 of this subpart; or

(2) a well for which there is no planned investment.

(b) In order to apply for a special relief rate under this subpart, a first seller must have contractual authorization to charge and collect the specific special relief rate (in cents per MMBtu) proposed in its application at the time a filing is made under § 271.1005 (b)(1) or (d)(2) with the Commission.

§ 271.1004 Special relief rate.

(a) *For a planned investment project:*

(1) The special relief rate for a planned investment project, other than a small project as defined in § 271.1007(d)(1), shall be the rate, in cents per unit of production (MMBtu), which is the sum of the following two components:

(i) a component which is the rate under which it is predicted that the applicant will earn a 15 percent true yield on its investment in the project, after allowance for Federal income tax; and

(ii) a component which is the rate under which the applicant will recover operating expenses for the project.

(2) The component of the special relief rate described in subparagraph (1)(i) of this paragraph shall be determined using the discounted cash flow method, as described in the Appendix to this Subpart, and shall be constant over the life of the project. The values used in the discounted cash flow computation shall reflect:

(i) only that investment which is incurred in completing the eligible project, and which is incurred:

(A) on or after the date an application was filed under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77 of this chapter, provided that the applicant has complied with § 271.1005(d)(1); or

(B) on or after the date an application was accepted under §271.1007(a)(1)(iv) in the case of applications to which subclause (A) does not apply.

(ii) the net working interest (gross interest less royalty interest) production (in MMBtu's) of all hydrocarbons estimated to be produced over the life of the project;

(iii) depreciation computed on a unit of production (MMBtu) basis;

(iv) a discount rate of 15 percent;

(v) an allowance for Federal income tax which is the marginal effective Federal income tax rate attributable to income from the project. The rate shall be the statutory rate applicable to such additional taxable income of the investor minus any applicable percentage depletion allowance or investment tax credits.

(3) The component of the special relief rate described in subparagraph (1)(ii) of this paragraph shall be determined for each calendar month as follows:

(i) By using the formula

$$Rc = \frac{Rp \times I \times Vp}{Vc}$$

Where:

Rc = The rate for the current month;
Rp = The rate for the previous month;
I = The inflation adjustment for the current month as published by the Commission under § 271.107(c);
Vp = Actual gross volume (Mcf) of gas delivered during the previous month in which production occurred;
Vc = Actual gross volume (Mcf) of gas delivered during the current month occurred.

(ii) For the initial delivery period (the period prior to and including the first full calendar month) the rate for the previous month (Rp) shall be determined by dividing the first year's estimated operating expense as determined under clause (iv) of this subparagraph, by the net working interest (gross interest less royalty interest) production (in MMBtu's) of hydrocarbons estimated to be produced during the first year of the project.

(iii) For the initial delivery period (the period prior to and including the first full

calendar month) the actual gross volume (Mcf) of gas delivered during the previous month (Vp) shall be the annualized (divided by 12) gross volume of gas estimated to be produced during the first year of the project.

(iv) The first year's estimated operating expense, shall be estimated for the first year in which deliveries are made under the special relief rate according to the following standards:

(A) operating expenses shall be estimated on the basis of normal, recurring operating and maintenance expenses, incurred and charged on the books and records of the producer for the production of hydrocarbons from the project;

(B) regulatory expense which shall be determined by multiplying the estimated first year's net working interest (gross interest less royalty interest) gas production (in MMBtu's) by $.001;

(C) a 15 percent return on working capital allowance which shall be determined by multiplying the estimated operating expense as defined in this clause (exclusive of regulatory expense and return on working capital allowance but inclusive of an allowance for Federal income tax) by .01875 (12.5 percent working capital allowance times a 15 percent rate of return) and dividing the product by a divisor of one minus the marginal effective tax rate applicable to the applicant under Subparagraph (2)(v) of this paragraph.

(D) Operating expense shall not include capital investment, depreciation, depletion, amortization, return on investment (profit), amounts repaid on borrowed funds, State income taxes, Federal income tax (except as allowed for in subclause (C) of this clause) any overhead which is not directly related and charged to the project, and any other adjustments allowed under Subpart K of this part.

(4) The following standards shall apply in the determination of the special relief rate under this paragraph:

(i) Only those expenditures shall be considered which are prudently incurred and which are in line with comparable industry expenditures for such equipment, services and expenses for similar projects.

(ii) Investment incurred prior to one year before the commencement of deliveries attributable to the projects shall be treated as if incurred at the time of commencement of deliveries, absent reasonable justification that a return should be allowed on investments incurred over a longer period of time.

(b) *For a well for which there is no planned investment:*

(1) The special relief rate for gas sold from a well for which there is no planned investment shall be the rate, in cents per unit of production (MMBtu's), under which it is predicted that the applicant will recover those out-of-pocket expenses which are reasonably assigned or allocated to gas production from the well and an incentive allowance of 5 percent after allowance for Federal income tax. Such rate, which will vary monthly according to changes in production and the rate of inflation, shall be determined for each calendar month as follows:

(i) By using the formula set forth in paragraph (a)(3)(i) of this section.

(ii) For the initial delivery period (the period prior to and including the first calendar month) the rate for the previous month (Rp) shall be determined by dividing the first year's estimated out-of-pocket expense as determined under paragraph (b)(2) of this section by the net working interest (gross interest less royalty interest) production (in MMBtu's) of hydrocarbons estimated to be produced during the first year of the project.

(iii) For the initial delivery period (the period prior to and including the first full calendar month) the actual gross volume (Mcf) of gas delivered during the previous month (Vp) shall be the annualized (divided by 12) gross volume of natural gas estimated to be produced during the first year of the project.

(2) The following shall apply in the determination of the special relief rate under this paragraph:

(i) Out-of-pocket expense shall be estimated for the first year on the basis

of normal, recurring operating and maintenance expenses, incurred and charged on the books and records of the producer for the production of hydrocarbons from the well, and may include:

(A) regulatory expenses as defined in paragraph (a)(3)(vi)(A) of this section;

(B) an incentive allowance of 5 percent after allowing for Federal income tax shall be determined by multiplying the out-of-pocket expense as defined in this clause (exclusive of regulatory expense an incentive allowance) by .05 and dividing the product by a divisor of one minus the marginal effective tax rate applicable to the applicant under subparagraph (2)(v) of this paragraph; and

(ii) Only those out-of-pocket expenses shall be considered which are to be prudently incurred and which are in line with comparable industry expenditures for such operation and maintenance for similar wells.

(iii) Out-of-pocket expense shall not include capital investment, depreciation, depletion, amortization, return on investment (profit), amounts repaid on borrowed funds State income taxes, Federal income taxes (except as allowed for under subparagraph (2)(i)(B) of this paragraph), any overhead which is not directly related and charged to the well and any other adjustments allowed under Subpart K of this part.

§ 271.1005 Application.

(a) *Scope of application.* A first seller shall make a separate application for each planned investment project or well for which there is no planned investment for which authority to charge and collect a special relief rate is sought.

(b) *Commencement of proceedings.* Except in the case of pending applications as provided in paragraph (d) of this section, a first seller shall commence a proceeding under this subpart by filing an initial application containing the applicable information required in § 271.1011 (a) through (b).

(c) *Supplemental applications for certain planned investment projects.* In the case of a planned investment project which does not qualify as either a small project under § 271.1007(d)(1) or a project subject to the provisions of paragraph (b)(2) of this section, the first seller shall file a supplemental application containing the applicable information required in § 271.1011(e) within 60 days of completing the planned investment project.

(d) *Pending applications.* The following provisions shall apply to pending applications filed before the effective date of this subpart under §§2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77 of this chapter:

(1) The application shall be deemed withdrawn for failure to go forward unless the applicant commences proceedings under this subpart by filing within 30 days of the effective date of this subpart:

(A) a notice of intent to proceed with the application under the requirements of this subpart; and

(B) a statement that it believes that the natural gas to be produced from the project or well qualifies for special relief under §§ 271.1001 and 271.1003(a) of this subpart.

(2) Subsequent to or concurrent with the filing of the notice required in subparagraph (1) of this paragraph the applicant shall:

(i) make a filing or filings conforming the application to the requirements in this subpart; or

(ii) file a statement that it believes the application conforms to the requirements of this subpart, that it does not intend to make a conforming filing and that it wishes to have the application reviewed under the requirements of this subpart, as filed.

(3) An application shall not be considered as conforming to the requirements of this subpart unless:

(A) In the case of a planned investment project other than a small project, the application contains the applicable information required in § 271.1011(e); or

(E) in cases of small projects and wells for which there is no planned

investment, the application contains the applicable information required in § 271.1011 (a) through (d).

(4) In the case of a planned investment project (other than a small project) completed prior to the date of issuance of this subpart in final form, the application shall be deemed to conform to the requirements of this subpart if it contains the information required in § 271.1011(e).

(e) *Form of submission.* Each application, supplemental application, conforming filing or notice of intent to proceed filed under this subpart shall be submitted in an original and three copies and shall be subscribed under oath by at least one working interest owner seeking special relief in the application.

(f) *Notice.* (1) Each initial application, supplemental application or conforming application filed under this subpart shall include a proposed notice which shall state the applicant's name, the date the application was filed under this subpart and the special relief rate requested. The proposed notice shall conform to the following form:

United States of America

Federal Energy Regulatory Commission

(Name of Applicant) ———————

Notice of Application for Special Relief

On (date application was filed), name of applicant) filed with the Federal Energy Regulatory Commission an application for special relief under Subpart J of Part 271 wherein (name of applicant) sought (special relief rate requested) for sales of natural gas to (name of purchaser).

The procedures applicable to the processing of this special relief application are found in 18 C.F.R. §§ 271.1001–271.1011.

Any person desiring to participate in this proceeding shall file a petition to intervene in accordance with the provisions of 18 C.F.R. § 271.1006. Except as otherwise provided in § 271.1006, all petitions to intervene shall be filed within 15 days after publication of this notice in the **Federal Register.**

(2) The applicant shall serve a copy of any initial application, supplemental application or conforming filings on each purchaser to whom sales of the natural gas for which the special relief rate is sought are made.

(3) Staff may require the applicant to provide additional service and shall caused notice of any initial application, supplemental application or conforming filing to be published in the **Federal Register.**

(4) The certificate of service required under § 1.17 of this chapter shall indicate the names and addresses of all persons served.

§ 271.1006 Intervention.

(a) *Petition.* A petition to intervene shall be made under the provisions of § 1.8 of this chapter except that it shall be filed within 15 days after service of any application or conforming filing. If a person has not been served with an application, a petition to intervene under § 1.8 shall be filed within 15 days after publication of notice of the application in the **Federal Register.**

(b) *Action by Staff.* Staff shall grant or deny all petitions filed under this section.

§ 271.1007 Review by staff.

(a) *Procedures for applications for certain planned investment projects.* The following procedures shall apply to applications for planned investment projects (other than a small project) filed under § 271.1005(b):

(1) In acting on an initial application for a planned investment project filed under § 271.1005(b) the staff may:

(i) notify the applicant within 60 days of filing of deficiencies in such application;

(ii) request within 60 days that the applicant provide additional information under paragraph (f)(2) of this section;

(iii) reject the application:

(A) for filing deficiencies if the applicant has not submitted the information required under § 271.1005 within 30 days after issuance of a letter

notifying the applicant of filing deficiencies in the application;

(B) for failure to provide additional information as required in paragraph (f)(2) of this section within a reasonable time after it is requested;

(C) upon determining that the natural gas to be produced from the planned investment project does not qualify for special relief under §§ 271.1001 and 271.1003, or that the proposed special relief rate has not been computed in accordance with the requirements of § 271.1004.

(iv) Accept the application upon determining that:

(A) The applicant has complied fully with the filing requirements of § 271.1005 and has supplied all additional information requested under paragraph (f)(2) of this section; and

(B) The application on its face meets the requirements of §§ 271.1001 and 271.1003, and that the special relief rate has been computed in accordance with the requirement of § 271.1004 of this subpart.

(2) Effect of acceptance of an initial application filed under § 271.1005(b) shall authorize the applicant to include in its supplemental application filed under § 271.1005(c) those investments and expenses permitted under § 271.1004 which were made or incurred for the project subsequent to such acceptance, but shall not imply approval of any expenditures included in the application.

(3) In acting on a supplemental application filed under § 271.1005(c) for a planned investment project, as described in paragraph (a) of this section the Staff may:

(i) notify the applicant within 60 days of such filing of filing deficiencies in the application or request that the applicant provide additional information under paragraph (f)(2) of this section;

(ii) reject the application for the reasons set forth in subparagraph (1)(iii) (A) through (C) of this paragraph;

(iii) issue a Staff report which shall:

(A) recommend approval of a specified special relief rate not in excess of the proposed rate, and state the basis for recommending such rate and any dispute of factual assertions made by the applicant; and

(B) be served on all persons specified in paragraph (e) of this section.

(4) Issuance of a staff report shall entitle all persons entitled to service of such report under paragraph (e) of this section to submit comments on the report within 30 days of the date of issuance of such report, and shall place the application before the Director of the Office of Pipeline and Producer Regulation (Director) for determination under § 271.1008.

(b) *Procedures for pending applications for planned investment projects.* (1) In acting on an application filed under § 2.56a(g), 2.56(h), 2.75, 2.76, or 2.77, for a planned investment project other than a small project the Staff may:

(i) notify the applicant within 60 days of the receipt of a conforming filing under § 271.1005(d)(2), of filing deficiencies in the application;

(ii) request within 60 days that the applicant provide additional information under paragraph (f)(2) of this section;

(iii) reject the application for the reasons set forth in paragraph (a)(1)(iii) (A) through (C) of this section;

(iv) issue a Staff report which shall:

(A) Recommend approval of a specified special relief rate not in excess of the proposed rate, and state the basis for recommending such rate and any dispute of factual assertions made by the applicant;

(B) Be served on all persons specified in paragraph (e) of this section.

(2) Issuance of a Staff report shall entitle all persons entitled to service of such report under paragraph (e) of this section to submit comments on the report within 30 days of the issuance of this report and shall place the application before the Director of the Office of Pipeline and Producer Regulation (Director) for determination under § 271.1008.

(c) *Procedures for applications for wells for which there is no planned investment.* (1) In acting on an application or conforming filing made under § 271.1005(d)(2) for a well for

which there is no planned investment, the Staff may:

(i) notify the applicant within 60 days of such filing of filing deficiencies in the application or request that the applicant provide additional information under paragraph (f)(2) of this section;

(ii) reject the application for the reasons set forth in paragraph (a)(1)(iii) (A) through (C) of this section;

(iii) issue a Staff report which shall:

(A) Recommend approval of a specified special relief rate not in excess of the proposed rate, and state the basis for recommending such rate and any dispute of factual assertions made by the applicant;

(B) Be served on all persons specified in paragraph (e) of this section.

(2) Issuance of a Staff report shall entitle all persons entitled to service of such report under paragraph (e) of this section to submit comments on the report within 30 days of the issuance of such report and shall place the application before the Director of the Office of Pipeline and Producer Regulation (Director) for determination under § 271.1008.

(d) *Procedures for small projects.* (1) For purposes of this subpart, a small project is defined as a planned investment project which meets the following criteria at the time an application for special relief is made under § 271.1005(b)(1), or, in the case of a pending application, at the time conforming filings are made under § 271.1005(d)(2):

(i) the total rate proposed for the sale of natural gas (exclusive of State serverance taxes as defined in § 271.1101(a)) is no more than the applicable rate for large producer sales as established under section 106(a) of the NGPA;

(ii) the planned development or production enhancement will result in estimated additional revenues over the life of the project to the applicant or less than 100,000 times that rate; and

(iii) the proposed investment in the project exceeds 25 percent of the estimated additional revenues to be generated by the project.

(2) A planned investment project which meets the requirements for a small project in subparagraph (1) of this paragraph and which otherwise qualifies for special relief under the requirements of § 271.1001 and § 271.1003 of this subpart shall receive the proposed special relief rate for the sale of gas from the project.

(3) In acting on any application described in subparagraph (1) of this paragraph, the Staff may:

(i) notify the applicant within 60 days of such filing of filing deficiencies in the application;

(ii) request that the applicant provide additional information under paragraph (f)(2) of this section;

(iii) reject the application:

(A) for the reasons set forth in paragraph (a)(1)(iii) (A) through (B) of this section; or

(B) upon determining that the application fails on its face to qualify for special relief under §§ 271.1001 or 271.1003; or

(C) upon determining that the planned investment project is not a small project under the requirements of subparagraph (1) of this paragraph; and

(iv) issue a Staff report which shall:

(A) recommend approval of the proposed special relief rate, and state the basis for recommending such rate and any dispute of factual assertions made by the applicant;

(B) Served on all persons specified in paragraph (e) of this section.

(4) Issuance of a Staff report shall entitle all persons entitled to service of such report under paragraph (e) of this section to submit comments on the report within 30 days and shall place the application before the Director of the Office of Pipeline and Producer Regulation (Director) for determination under § 271.1008.

(e) *Notice of Staff action.* Notice of all Staff action specified in paragraphs (a) through (d) of this section, except the issuance of deficiency letters or requests for additional information, shall be served upon all persons entitled to service under § 271.1005(f) and all

persons granted the right to intervene under § 271.1006.

(f) *Investigation and evaluation.*

(1) All filings made in connection with the application for special relief shall be considered in evaluating the application.

(2) The Staff may request additional information relevant to the application, and the applicant shall supply such information.

(3) The Staff may investigate the basis for any statement in the application or conforming filing, may conduct an audit, and may use in its evaluation any relevant fact obtained in such an investigation or audit.

(4) The Staff may solicit and accept written submissions from intervenors or third persons relevant to the application.

(5) If the Staff obtains information under subparagraph (3) or (4) of this paragraph and relies upon such information in making a decision under this section, the applicant shall be advised of such information and shall be given 10 days to respond to such information.

(6) The Staff may conduct a conference on the application in accordance with procedures it determines will most expeditiously further the purpose of such conference. A conference shall be convened only after actual notice of the time, place, and nature of the conference has been served upon all persons entitled to service under paragraph (e) of this section. All persons served may attend the conference, and the Staff may use in its evaluation any relevant information obtained through such conference.

(g) *Definition of "Staff".* For purposes of this subpart, "Staff" means an employee of the Commission who has been appointed by the Director, but shall not include the Director.

§ 271.1008 Determination by the Director of the Office of Pipeline and Producer Regulation.

(a) *Determination.* The Director (or his designee) shall review a Staff report issued and all public comments filed under § 271.1007 and shall determine the special relief rate or recommend other appropriate action on the application to the Commission.

(b) *Finality.* Any determination of a special relief rate made by the Director under this section shall become final 30 days after notice is published in the **Federal Register** unless, during such period:

(1) a petition appealing the determination is filed under § 271.1009; or

(2) the Commission directs that the determination order be submitted to it for review under § 271.1009.

(c) *notice of Director's determination.* Notice of the determination or recommendation made by the Director under this section shall be served upon the Commission and upon all persons specified in § 271.1007 and shall be published in the **Federal Register.**

§ 271.1009 Appeals to the commission.

(a) *Petition for review.* A petition appealing any of the following actions shall be filed within 30 days of such action:

(1) a determination of a special relief rate made by the Director under § 271.1008;

(2) staff acceptance or rejection under § 271.1007 of an initial or supplemental application;

(3) staff denial under § 271.1006 of a petition to intervene.

(b) *Who may petition.* A person may file a petition under paragraph (a) of his section if that person:

(1) Is adversely affected by the action appealed; and

(2) except in the case of appeals regarding denial of intervention under § 271.1006, is specified in § 271.1007(e).

(c) *Contents of petition.* The petition shall include a copy of the Notice of action which is being contested and a complete statement of the petitioner's factual or legal objections to the action taken.

(d) *On motion of the Commission.* The Commission may, on its own motion, direct that the action by Staff or the Director be submitted to it for review.

(e) *Action by the Commission.* Review of actions by the Staff and the Director shall be based on the record and shall provide such opportunity for additional submissions, including hearings, as the Commission deems appropriate.

§ 271.1010 Retroactive collection.

(a) *No planned investment.* Except as provided in paragraph (c) of this section, and upon final approval of a special relief rate for a well for which there is no planned investment, the applicant may charge and collect that rate retroactively for sales of gas from the well beginning on the date the application was filed under § 271.1005(b).

(b) *Planned investment project.* Except as provided in paragraph (c) of this section, and upon final approval of a special relief rate for a planned investment project, including a small project as defined in § 271.1007(d)(1), the applicant may charge and collect that rate retroactively for sales of gas from the project beginning on the date deliveries from the project were commenced.

(c) *Pending applications.* Upon final approval of a special relief rate for a pending application filed under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77, for which a notice was filed under § 271.1005(d)(1), the applicant may charge and collect the approved rate retroactively for sales of gas from the project:

(1) beginning on the earlier of the following, if such application was filed under § 2.75 of this chapter:

(i) the date notice of intent to proceed was filed under § 271.1005(d)(1); or

(ii) the date 9 months following commencement of deliveries under the contract to which such special relief rate applies.

(2) beginning on the date such notice was filed under § 271.1005(d)(1), if such application was filed under §§ 2.56a(g), 2.56b(h), 2.76, or 2.77 for a well for which there is no planned investment;

(3) beginning on the later of the following, if such application was filed under §§ 2.56a(g), 2.56b(h), 2.76 or 2.77 for a planned investment project:

(i) the date notice was filed under § 271.1005(d)(1); or

(ii) the date on which deliveries from the project were commenced.

(d) *Verification by first purchaser.* In order to make retroactive collections contingent on commencement of deliveries, the applicant shall cause the first purchaser to submit to the Commission verification of such commencement.

§ 271.1011 Filing requirements.

(a) *For certain planned investment projects.* Except as provided in paragraph (d) of this section for small projects, a filing made under § 271.1005(b) for a planned investment project shall include the following information:

(1) the name of the applicant;

(2) the applicant's principal place of business;

(3) the name and title, mailing address, and telephone number of the person responsible for the application;

(4) the working interest owners who are covered by the application and their respective percentages in the project and identification of any interest owners not covered by the application (including full details where the working interest varies for investment, operating expense, revenue, or any other reason);

(5) the royalty, overriding royalty, and non-operating interest owners associated with the project, according to category, including their respective percentages of the project and including a statement of any relationship to the project through ownership or employment or any other relationship;

(6) for each working interest owner covered by the application, the FERC certificate docket number and the FERC gas rate schedule number under which the gas has been or will be sold (applicable only to gas qualifying under section 104 or 106(a) of the NGPA);

(7) the name and address of the first purchaser;

(8) the maximum lawful price (in cents per MMBtu) each working interest owner covered by the application would be entitled to collect under the NGPA

without reference to whether a contractual right exists to charge such price;

(9) the proposed special relief rate (in cents per MMBtu) computed in accordance with § 271.1004 or § 271.1007(d)(1), if applicable;

(10) An executed copy of each document to which the purchaser is a party which provides for the payment of the proposed special relief rate, as required in § 271.1003(b);

(11) The location of all facilities associated with the proposed project (including the State, county or parish, and field and well designations);

(12) The estimated recoverable reserves of gas (in Mcf's) and liquids (in bbls.) for the project, including a schedule of the project's anticipated annual production for each type of reserve (in Mcf's or bbls.);

(13) an estimate of future operating expenses, on a 100 percent working interest basis, by year, for the first year in which deliveries are made under the special relief rate from the eligible project;

(14) if Federal income tax expenses have been claimed under § 271.1004(a)(2)(v), the calculation establishing the amount of taxes claimed;

(15) a detailed description of the project on a well-by-well or platform-by-platform basis and an estimate of the attendant costs segregated by major category, a proposed timetable for work and expenditures, and a discounted cash flow analysis showing the derivation of the special relief rate sought, consistent with § 271.1004; and

(16) at the option of the applicant, the data relating to the determination of reserves and gas deliverability required under paragraph (e)(4) of this section for supplemental applications.

(b) *Additional information for certain planned investment projects.* A filing made under § 271.1005(b) for a planned investment project consisting of planned production enhancement work on a previously producing well, or work serving a group of wells shall include the following information in addition to that required in paragraph (a) of this section:

(1) an explanation of why the work is necessary;

(2) the price currently collected (in cents/MMBtu);

(3) the average unit Btu content (as determined in accordance with § 270.204 of this chapter) of the gas at the point of measurement for payment and the location of the point of delivery of the gas to the purchaser;

(4) engineering and economic studies, equipment and service contracts and bids, and any other related documents necessary to substantiate the proposed expenditures and special relief rate;

(5) A schedule of operating expenses for the project on a 100 percent working interest basis detailed by cost item for the 2 most recent 12-month periods prior to the date of filing under § 271.1005 (b) or (d)(2), including a description of the method or basis for assigning or allocating indirect costs or overheads to the lease and well; and

(c) *For wells for which there is no planned investment.* A filing made under § 271.1005 (b) or (d)(2) for a well for which there is no planned investment shall include:

(1) the information required under paragraphs (a) (1) through (11) and (b) (2), (3), and (5), and (e)(4) (i), (v), and (viii) of this section; and

(2) an estimate of future operating expenses, on a 100 percent working interest basis, for the first year in which deliveries are made under the special relief rate from the eligible project.

(d) *For small projects.* A filing made under § 271.1005 (b) or (d)(2) for a project which qualifies as a small project under § 271.1007(d)(1) shall include the information required under paragraphs (a) (1) through (12), (b) (1) through (4) and (e)(4) of this section.

(e) *Supplemental applications and conforming filings.* A supplemental application for a planned investment project made under § 271.1005(c) or conforming filing under § 271.1005(d)(2) shall include:

(1) an estimate of the salvage value of the equipment involved in the project at

the end of its useful life in the project on an item-by-item basis;

(2) a list, segregated by major category, of equipment and service contracts, invoices, and any other related documents necessary to substantiate the expenditures claimed in subparagraph (6) of this paragraph;

(3) the average unit Btu content (as determined in accordance with § 270.204) of the gas at the point of measurement for payment and the location of the point of delivery of the gas to the purchaser;

(4) the following data relating to the determination of reserves and deliverability of the gas to which the application applies:

(i) a map delineating the exact acreage in the project area and showing the location of each completed, abandoned or proposed well and other facilities associated with the project;

(ii) all electrical, acoustical, radioactive or other logs run on any well on the project acreage;

(iii) all core analyses, conventional or sidewall, from any cores taken from any well on the project acreage;

(iv) all tests, including open hole drill stem tests, wire line formation tests, initial production tests, single or multiple point backpressure tests, build-up or drawdown tests and subsurface pressure surveys run on any well drilled on the project acreage;

(v) tabulated production, by year and month, separately by products, including oil, gas, condensate and water for all well completions on the project acreage;

(vi) all well completion reports filed with the oil and gas regulatory authority having jurisdiction for wells drilled on the project acreage;

(vii) all analyses made on separator or well stream gas or separator liquids produced from the project acreage;

(viii) tabulation, by month and year, of any plant liquids credited back to the leases in the project acreage from any processing plant;

(ix) tabulated reservoir parameters by reservoir for all reservoirs that are actually producing or that have proven productive by actual formation tests on the project acreage or that can be reasonably demonstrated to underlie the project acreage;

(x) top of structure maps and isopach maps for all reservoirs that are actually productive or that have been proven productive by actual formation tests on the project acreage or that can be reasonably demonstrated to underline the project acreage; and

(xi) the current average pipeline pressure of the purchaser at each point of sale for all gas sold from the project acreage;

(5) in lieu of the information specified in subparagraph (4) of this paragraph, citation to the application for certificate authority to sell the gas or the FERC Gas Rate Schedule in which such information is filed;

(6) a detailed description of the completed project along with the actual costs incurred, segregated by major category, and a discounted cash flow study reflecting actual costs computed in accordance with § 271.1004; and

(7) any additional information which the applicant wishes to have considered.

Special Relief Rate Determination—Prepared by the Staff of the Federal Energy Regulatory Commission

The cost calculations presented herein demonstrate the methodology the staff would use to determine a special relief rate for a project in conformance with the regulations for special relief as set forth in Subpart J of Part 271. The methodology allocates costs between natural gas and liquids by the straight Btu method.

I. The Computation of the Two-Component Rate for Planned Investment Projects Other Than Small Projects

The Hypothetical Project

The hypothetical planned investment project used in this example of the determination of a special relief rate consists of a new well drilled in a known gas field at an actual cost of $3,000,000, 70 percent of which represents intangible costs. The new well is successfully drilled and completed in a formation producing

natural gas and liquids (condensate). It is estimated that the well will cost $12,000 to operate during the first year, have a productive life of 10 years, and produce for delivery and sale the gross quantities of natural gas (1030 Btu/cu. ft.) and condensate (5.448 MMBtu/Bbl) set forth in attached Schedule 1, Columns (b) and (c) subject to a 12.5 percent royalty interest.

Calculation of the Special Relief Rate

The following pages show the formulae and calculations which produce a starting special relief rate of $2.531 per MMBtu for the project. Schedules 1 through 3 show the derivation of the numbers used in the calculations. Schedule 4, the proof of the discounted cash flow method, shows that the discounted cash flow of the investment in and Federal income tax liability of the project is zero when the rate for this component, $2.492, is used.

This is a starting special relief rate related to an annualized gross gas production of 27,046 Mcf. The actual rates for deliveries during the period prior to and including the first full calendar month of production and subsequent calendar months would be determined by recomputing the component related to operating expense ($.039) in accordance with the procedure set forth in § 271.1004(a)(3)(i) and adding the component related to investment ($2.492) which remains constant over the life of the project. An illustration of the calculation of subsequent rates appears on pages 8 and 9.

Determination of Rate Components

1. *The component reflecting a 15 percent true yield on investment.*

This component is computed using the discounted cash flow methodology. The basic equation is:

Discounted Annual Revenue—(Discounted Investment + FIT) = 0; which becomes—
R (Discounted Production) = Discounted Investment + FIT Tax Rate [R (Discounted Production)—Discounted Income Tax Deductions] – Discounted Investment Tax Credit.

For the hypothesis given, the values of the variables are:

Variable	Value	Source
R, which is the rate	(1)	
Discounted production (MMBtu)	1,254,230	Schedule 2, col. (e), line 13.
Discounted investment	$2,977,753	Schedule 2, col. (f), line 13.
FIT tax rate (percent)	46%	Current statutory rate.
Discounted income tax deductions	$2,607,962	Schedule 3, col. (g), line 12.
Discounted investment tax credit	$90,000	Schedule 3, col. (h), line 12.

[1] Unknown.

The solution of the equation follows:

1,254,230 R = 2,977,753 + 46 (1,254,230 R – 2,607,962) – 90,000
677,284 R = 1,688,090
R = $2.49244 per MMBtu (rounds to $2.492)

2. The component reflecting recovery of operating expense.

This component is computed using the estimated first-year's operating expense and net working interest production volume (in MMBtu). The equation is:

$$R = \frac{\text{Operating expense} + \text{return on working capital} + \text{regulatory expense}}{\text{Net working interest production}}$$

For the hypothesis given, the values of the variables are:

Variable	Value	Source
R, which is the rate	(1)	
Operating expense	$12,000	Hypothesis
Returning on working capital	$417	($12,000 × .01875)[2] × (1 – FIT tax rate)
Regulatory expense	$292	292,487 × $.001
FIT tax rate (percent)	48	Current statutory rate
N.W.I. production (MMBtu)	325,000	Schedule 1, col. (h), line 1.

[1] Unknown.
[2] 12.5 percent working capital allowance times 15 percent rate of return.

The solution of the equation follows:

$$R = \frac{12,000 + 417 + 292}{325,000}$$

R = $0.039105 per MMBtu (rounds to $0.039)

Schedule 1

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PRODUCTION VOLUMES

Line No.	Year	Gross Volumes		N.W.I. Volumes		N.W.I. Production Unit		
		Gas (Mcf)	Liquids (Bbls)	Gas (Mcf)	Liquids (Bbls)	Gas (MMBtu)	Liquids (MMBtu)	Total (MMBtu)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1	324,546	6,818	283,978	5,966	292,497	32,503	325,000
2	2	299,587	6,293	262,139	5,506	270,003	29,997	300,000
3	3	274,616	5,769	240,289	5,048	247,498	27,502	275,000
4	4	249,653	5,244	218,446	4,589	224,999	25,001	250,000
5	5	224,688	4,720	196,602	4,130	202,500	22,500	225,000
6	6	199,722	4,195	174,757	3,671	180,000	20,000	200,000
7	7	149,787	3,147	131,064	2,754	134,996	15,004	150,000
8	8	124,828	2,622	109,225	2,294	112,502	12,498	125,000
9	9	99,858	2,098	87,376	1,836	89,997	10,003	100,000
10	10	49,929	1,049	43,688	918	44,999	5,001	50,000
11	Total	1,997,214	41,955	1,747,564	36,712	1,799,991	2,000,009	2,000,000

Source:

Column (b) - Estimated Natural Gas Production.
Column (c) - Estimated Liquids (condensate) Production.
Column (d) - Column (b) times .875 net working interest.
Column (e) - Column (c) times .875 net working interest.
Column (f) - Column (d) times 1.03 MMBtu/Mcf.
Column (g) - Column (e) times 5.448 MMBtu/Bbl.
Column (h) - Sum of Columns (f) and (g).

Schedule 2

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PRESENT VALUE OF PRODUCTION AND INVESTMENT

Line No.	Year	N.W.I. Production (MMBtu)	Investment ($)	Discount Factors	Discounted Production (MMBtu)	Discounted Investment ($)
	(a)	(b)	(c)	(d)	(e)	(f)
1	Start		3,000,000	1.00000		3,000,000
2	1	325,000		.93250	303,063	
3	2	300,000		.81087	243,261	
4	3	275,000		.70511	193,905	
5	4	250,000		.61314	153,285	
6	5	225,000		.53316	119,961	
7	6	200,000		.46362	92,724	
8	7	150,000		.40315	60,473	
9	8	125,000		.35056	43,820	
10	9	100,000		.30484	30,484	
11	10	50,000		.26508	13,254	
12	End		(90,000)	.24719		(22,247)
13	Total	2,000,000	2,910,000		1,254,230	2,977,753

Source:

Column (b) - Net Working Interest Production from Schedule 1, Column (h).
Column (c) - Line 1: Total Investment.
Line 12: Net Salvage Value of Tangible Investment.
Column (d) - Lines 2-11 are mid-year factors at 15%.
Line 12 is the end-of-year factor for year 10 at 15%.
Column (e) - Column (b) times Column (d).
Column (f) - Column (c) times Column (d).

Schedule 3

PRESENT VALUE OF INCOME TAX DEDUCTIONS AND INVESTMENT TAX CREDIT

Line No.	Year	Intangible Drilling Costs ($) (b)	Depreciation ($) (c)	Total Deductions ($) (d)	Investment Tax Credit ($) (e)	Discount Factors (f)	Discounted Total Deductions ($) (g)	Discounted Investment Tax Credit ($) (h)
1	Start	2,100,000		2,100,000	90,000	1.00000	2,100,000	90,000
2	1		131,625	131,625		.93250	122,740	
3	2		121,500	121,500		.81087	98,521	
4	3		111,375	111,375		.70511	78,512	
5	4		101,250	101,250		.61314	62,080	
6	5		91,125	91,125		.53316	48,584	
7	6		81,000	81,000		.46362	37,553	
8	7		60,750	60,750		.40315	24,491	
9	8		50,625	50,625		.35056	17,747	
10	9		40,500	40,500		.30484	12,346	
11	10		20,250	20,250		.26508	5,368	
12	Total	2,100,000	810,000	2,910,000	90,000		2,607,962	90,000

Source:

Column (b) - 70% of Total Investment of $3,000,000.
Column (c) - Unit-of-Production Depreciation of Net Tangible Investment ($810,000). Net Tangible Investment is 30% of Total Investment of $3,000,000 less Salvage Value of $90,000.
Column (d) - Sum of Columns (b) and (c).
Column (e) - Investment Tax Credit is 10% times Tangible Investment of $900,000. Tangible Investment is 30% times Total Investment of $3,000,000.
Column (f) - From Schedule 2, Column (d).
Column (g) - Column (d) times Column (f).
Column (h) - Column (e) times Column (f).

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Schedule 4

DISCOUNTED CASH FLOW AT $2.49244 per MMBtu

Line No.	Year	N.W.I. Production (MMBtu)	Revenue ($)	Investment ($)	Federal Income Tax ($)	Net Cash Flow ($)	Discount Factor	Discounted Cash Flow ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Start			3,000,000	(1,056,000)	(1,944,000)	1.00000	(1,944,000)
2	1	325,000	810,043		312,072	497,971	.93250	464,358
3	2	300,000	747,732		288,067	459,665	.81087	372,729
4	3	275,000	685,421		264,061	421,360	.70511	297,105
5	4	250,000	623,110		240,056	383,054	.61314	234,866
6	5	225,000	560,799		216,050	344,749	.53316	183,806
7	6	200,000	498,488		192,044	306,444	.46362	142,074
8	7	150,000	373,866		144,033	229,833	.40315	92,657
9	8	125,000	311,555		120,028	191,527	.35056	67,142
10	9	100,000	249,244		96,022	153,222	.30484	46,708
11	10	50,000	124,622		48,011	76,611	.26508	20,308
12	End			(90,000)		90,000	.24719	22,247
13	Total	2,000,000	4,984,880	2,910,000	864,444	1,210,436		-0-

Source:

Column (b) - Net Working Interest Production from Schedule 1, Column (h).
Column (c) - Column (b) times $2.49244.
Column (d) - Total Investment.
Column (e) - Line 1: [(Column (c) minus Schedule 3, Column (d)) times 46%] minus Schedule 3, Column (e).
Lines 2-11: (Column (c) minus Schedule 3, Column (d)) times 46%.
Column (f) - Column (c) less Columns (d) and (e).
Column (g) - From Schedule 2, Column (d).
Column (h) - Column (f) times Column (g).

Illustrating the Calculation of Subsequent Rates

This illustration showing the calculation of subsequent rates once the starting rate has been determined is based on the following hypothesis:

1. Deliveries under the special relief rate start in mid-March.

2. Actual gross gas deliveries in April are 26,000 Mcf.

3. The published inflation adjustment for April is 1.00690.

4. Actual gross gas deliveries in May are 24,000 Mcf.

5. The published inflation adjustment for May is 1.00875.

(a) To calculate the rate for the initial delivery period, mid-March through April, you simply:

1. Recalculate the component related to operating expense (Rc) using the formula set forth in § 271.1004(a)(3)(i) and the following values:

Variable	Value	Source
Rp	$0.039	The value of the component related to operating expense in the starting rate.
I	1.00690	The published inflation adjustment as stated in the hypothesis.
Vp (Mcf)	27,046	The annualized gross gas production related to the starting rate.
Vc (Mcf)	26,000	The actual gross gas deliveries for April as stated in the hypothesis.

Thus:

$$R = \frac{.039 \times 1.00690 \times 27,046}{26,000}$$

= $0.040849 per MMBtu (rounds to $0.041)

2. Add the component related to investment ($2.492).

This results in a rate of $2.533 for deliveries during the period mid-March through April.

(c) To calculate the rate for deliveries during May, you simply:

1. Recalculate the component related to operating expense (Rc) using the same formula and the following values:

Variable	Value	Source
Rp	$0.041	The value of the component related to operating expense as determined above.
I	1.00875	The published inflation adjustment as stated in the hypothesis.
Vp (Mcf)	26,000	The actual gross gas deliveries for April as stated in the hypothesis.
Vc (Mcf)	24,000	The actual gross gas deliveries for May as stated in the hypothesis.

Thus:

$$R = \frac{.041 \times 1.00875 \times 26,000}{24,000}$$

= $0.044806 per MMBtu (rounds to $0.045)

2. Add the component related to investment ($2.492).

This results in a rate of $2.537 for deliveries during May.

(b) To calculate the rate for subsequent monthly periods, simply repeat the procedure in (b), above, using the values applicable to the variables.

II. The Computation of the Rate for a Well for Which There Is No Planned Investment

The Hypothetical Project

The hypothetical well for which there is no planned investment used in this example of the determination of a special relief rate consists of a currently producing well whose revenues are insufficient to cover the out-of-pocket expense incurred in its operation. It is estimated that during the next year, an out-of-pocket expenditure of $48,000 will be required to produce gross volumes of 72,000 Mcf of 1020 Btu per cu. ft. gas (73,440 MMBtu) and 200 Bbls. of 5,448 MMBtu per Bbl. condensate (1090 MMBtu). This gross production volume of 74,530 MMBtu is subject to a 12.5 percent royalty interest.

Calculation of The Special Relief Rate

The following page shows the formula and calcuation which produce a starting special relief rate of $.605 per MMBtu. This is a starting special relief rate related to an annualized gross production of 6,000 Mcf. The actual rates for deliveries during the period prior to and including the first full calendar month of production and subsequent calendar months would be determined by recomputing this rate in accordance with the procedure set forth in § 271.1004(a)(3)(i). An illustration of the calculation of subsequent rates appears on page 12.

Determination of Rate

The starting rate is computed using the estimated first-year's out-of-pocket expense and net working interest production volume (in MMBtu). The equation is:

$$R = \frac{\text{Out of pocket expense} + \text{incentive allowance} + \text{regulatory expense}}{\text{Net working interest production}}$$

For the hypothesis given, the values of the variables are:

Variable	Value	Source
R, which is the rate	( )	
Out of pocket expense	$48,000	Hypothesis.
Incentive allowance	$4,444	($48,000 × .05) ÷ (1–FIT tax rate)
Regulatory expense	$64	73,440 × .875 × $.001.
FIT tax rate (percent)	46	Current statutory rate.
N.W.I. production (MMBtu)	65,214	74,530 × .875

The solution of the equation follows:

$$R = \frac{48,000 + 4,444 + 64}{65,214}$$

R = $0.805165 per MMBtu (rounds to $0.805)

Illustrating the Calculation of Subsequent Rates

This illustration showing the calculation of subsequent rates once the starting rate has been determined is based on the following hypothesis:

1. Deliveries under the special relief rate start in mid-March.

2. Actual gross gas deliveries in April are 5,500 Mcf.

3. The published inflation adjustment for April is 1.00690.

4. Actual gross gas deliveries in May are 5,000 Mcf.

5. The published inflation adjustment for May is 1.00875.

(a) To calculate the rate for the initial delivery period, mid-March through April, you simply recalculate the starting rate (Rc) using the formula set forth in § 271.1004(a)(3)(i) and the following values:

Variable	Value	Source
Rp	$.805	The starting rate.
I	1.00690	The publsned inflation adjustment as stated in the hypothesis.
Vp (Mcf)	6,000	The annualized gross gas production related to the starting rate.
Vc (Mcf)	5,500	The actual gross gas deliveries for April as stated in the hypothesis.

Thus:

$$R = \frac{.805 \times 1.00690 \times 6,000}{5,500}$$

= $0.884242 per MMBtu (rounds to $0.884)

(b) To calculate the rate for deliveries during May, you simply recalculate the rate (Rc) using the same formula and the following values:

Variable	Value	Source
Rp	$.884	The rate determined above.
I	1.00875	The published inflation adjustment as stated in the hypothesis.
Vp (Mcf)	5,500	The actual gross gas deliveries for April as stated in the hypothesis.
Vc (Mcf)	5,000	The actual gross gas deliveries for May as stated in the hypothesis.

Thus:

$$Rc = \frac{.884 \times 1.00875 \times 5,500}{5,000}$$

= $0.980909 per MMBtu (rounds to $0.981)

(c) To calculate the rate for subsequent monthly periods, simply repeat the procedure in (b), above, using the values applicable to the variables.

Appendix B

January 15, 1980

Memorandum to: The Public File.

From: Office of the General Counsel.

Subject: Final Rule: Procedures Governing Applications for Special Relief Under Sections 104, 106, and 109 of the Natural Gas Policy Act of 1978, Docket No. RM79-67.

This memorandum outlines four major issues pertaining to the draft of the final rule in this docket which was presented to the Commission at the meeting of December 19, 1979. The Commission has solicited public comments and has established procedures for a panel discussion on these issues to be held before the Commission.

1. *The establishment of a ceiling for special relief rates.* The draft final rule imposes no upward limitation on a special relief rate. As a result, a producer who qualifies for special relief would be entitled to receive any rate, no matter how high, which is properly computed on the basis of actual expenditures prudently incurred using the formulae set forth in § 271.1004 of the rule. Although the contract authorization requirement was designed, in part, to impose as an indirect ceiling on the special relief rate the negotiated contract price, that purpose often may be frustrated by the failure of pipelines, who may pass through their costs to consumers, to negotiate for lower prices.

The Commission may be persuaded that in some cases the special relief rate calculated on the basis of recoverable costs is simply too high to justify production of gas and therefore, that

some ceiling on special relief rates should be imposed.

For this reason the Commission may wish to modify the final rule by adopting a provision which reserves to the Commission the authority to grant or to deny a special relief rate which exceeds some specified threshold. Such a provision would leave intact the delegation of authority to determine a rate to the Director of the Office of Pipeline and Producer Regulation (Director), except that the Director would have no authority to determine a rate which exceeds the higher of the maximum statutory price (natural gas priced under section 108 of the NGPA) or the maximum incentive price for high cost gas available under Commission regulation (established pursuant to Commission authority under section 107(c)(5) of the NGPA). In the event that a rate computed in accordance with the formulae and standards of this rule exceeds the statutory or regulatory ceiling, the application would be forwarded to the Commission which would grant the higher rate if it finds that to do so would be in the public interest.

Such a provision would be drafted to conform to the procedural scheme of the rule which provides a two-step review procedure for future applications for planned investment projects and a single review in the case of all other applications. In the case of future applications for planned investment projects where the proposed rate exceeds the ceiling, the Commission would determine whether to permit the higher rate at the stage of initial review, *i.e.*, at the point at which staff ordinarily "accepts" an application.[1] In all other cases, the Commission decision to permit or to deny an application for a rate which exceeds the ceiling would be made at the end of the one-step application process after the issuance of a staff report and upon a finding by the Director that the appropriate special relief rate is in excess of the ceiling.[2]

2. *The opportunity of an applicant for special relief to seek a higher maximum lawful price under some other section of the NGPA.* Under the rule as presently drafted, a producer who has obtained a special relief rate is not held to that rate for the life of the project. That is, he may at any time seek a determination enabling him to collect a higher incentive rate under some other section of Title I of the NGPA.

For example, a producer of gas from a new well may be subject to a maximum lawful price under section 109 of the NGPA if he has not sought a determination that he is eligible to collect a price under some other section. This producer may apply for and receive a special relief rate because the gas to be produced from the well would be subject to section 109, and later, if the final special relief rate proves to be lower than the section 103 price, seek a determination that the gas is eligible for the section 103 price. In effect, the regulation invites the use of special relief as a fallback measure in the case of the development of any new well. A producer may be tempted to seek special relief for each new well to take advantage of the possibility that the special relief rate could prove to be higher than the applicable maximum lawful price.

In other situations, the freedom to switch to other price categories may create a windfall to the producer. For example, a producer of gas subject to section 104 and also eligible to receive the section 103 price may seek a cost-based special relief rate because the section 103 price is an inadequate, or at least a lesser, incentive to undertake investment in the project. At the point of initial deliveries the cost-based special relief rate may be higher than the section 103 price. But because the section 103 price escalates more rapidly than the special relief rate, the section 103 price will catch up to and exceed the special relief rate; a producer who switches to the higher incentive rate will

[1] See, Final Rule, Procedures Governing Special Relief § 271.1007(a).

[2] *Id.* § 271.1007 (b), (c).

collect the higher cost-based rate in the early stages of production and enjoy the more rapid rate of escalation when the section 103 price comes to exceed the special relief rate.

To avoid this windfall and to prevent the use of special relief as a fallback supplanting the incentive scheme of Title I whenever the applicable incentive price yields a smaller rate of return, the Commission may wish to limit the producer's freedom to switch from special relief to another applicable maximum lawful price.

Option A—The Commission Could Require a Producer To Elect Either To Receive the Highest Maximum Lawful Price or To Seek a Special Relief Rate

Under this scheme a producer who applies for a special relief rate under these procedures would waive any right to collect a higher maximum lawful price under some other section of Title I.

Such a provision eliminates both the windfall and the recurring use of special relief as a fall-back measure. However, objections may be raised with regard to "the producer always wins rule" of section 101(5) of the NGPA, which provides that natural gas which qualifies for a maximum lawful price under more than one section of the NGPA is entitled to collect the highest of those prices.[3] Arguably, to require a producer to waive his right to collect a higher ceiling price is impermissible under section 101(5).

In answer to this objection, it must be noted that the Commission's authority to grant special relief is permissive; the essential conditions to the exercise of the Commission's authority are only that the special relief rate be higher than the maximum lawful price of section 104, 106 or 109 (whichever is applicable) and that the rate be just and reasonable within the meaning of the Natural Gas Act.[4] On this basis, it can reasonably be argued that the Commission may require a producer to elect not to seek another NGPA price as a quid pro quo for the opportunity to receive a special relief rate designed to assure him the recovery of all prospective costs plus a fifteen percent rate of return on his investment.

Beyond the question of statutory interpretation lies a further question regarding the relationship of such a waiver requirement to other policies of the NGPA. It can reasonably be argued that section 101(5) was designed with the expectation and intent that the producer would jump from one price level to another so that at any time he may collect the highest applicable maximum lawful price. Thus, although the parameters of the Commission's special relief authority may be sufficiently broad to permit the imposition of a waiver requirement, it may violate the intent of the NGPA to impose such a requirement. However, without the waiver, special relief could come to be the inevitable back-up measure supplanting the NGPA scheme of incentive pricing any time the NGPA rates yield less than the recovery of prospective costs plus a fifteen percent rate of return.[5] This use of special relief may run counter to the general purposes of the statutory scheme of the NGPA, and would justify the waiver requirement as consistent with the general scheme of the NGPA.

Option B—Deny Special Relief to Producers of Gas Which Qualify for a Section 104, 106, or 109 Price But Which May Also Be Eligible To Receive an Incentive Price Under Some Other Section

Under this scheme, the producer would be required, as a condition to

[3] Section 101(5) provides that: (i)f any gas qualifies under more than one provision of this title providing for any maximum lawful price or for any exemption from such a price with respect to any first sale of such natural gas, the provision which could result in the highest price shall be applicable.

[4] *See*, NGPA Sections 104(b)(2), 106(c), and 109(b)(2).

[5] Or any other rate of return which the Commission determines to be appropriate for rates set under this rulemaking. *See, infra*, Issue No. 4, at page 15.

receiving special relief, to apply for all price determinations for which he reasonably believes the gas may be eligible. If it is determined that the gas is eligible only for the section 104, 106 or 109 price, the special relief rate may be granted. If the gas is eligible for an incentive price, or if the producer chooses not to seek any applicable determinations, special relief would be denied.

Underlying such a provision is the assumption that the maximum lawful prices under sections 102, 103, 107, and 108 were intended to establish the maximum incentives to be offered to a producer to induce him to produce the natural gas subject to the incentive price: if his costs exceed the applicable incentive price, it is Congress' intent that the gas is not worth the higher price, and its production would have to await deregulation. Thus, it would be argued, it would be consistent with the incentive pricing scheme of Title I to exclude from eligibility for special relief any natural gas which also qualifies for a maximum incentive price under some price category.

There are two difficulties with this option. First, it may prove awkward to administer insofar as staff would be required to determine from the face of the application whether the natural gas from the project is likely to be eligible for an incentive price, thereby duplicating to some extent the functions of the jurisdictional agencies. More importantly, it may, as a matter of policy, be preferable to encourage present investment in gas production rather than to encourage a producer whose developmental costs exceed even the applicable incentive price to delay development until after deregulation.

Option C–Condition Special Relief on the Existence of a Contractual Provision Which Reserves the Right of the Pipeline To Pay the Special Relief Rate for the Life of the Project

Under this option, a special relief rate would be granted only if the producer has negotiated a contract which permits the pipeline to insist upon paying the special relief rate for the life of the project. A producer who wishes to switch from a special relief rate to a higher incentive or deregulated price would be required to renegotiate the contract thereby providing some assurance that a windfall would be averted. This option is attractive in that it clearly would not run afoul of the producer always wins rule and, it would avoid the difficulties inherent within Option B which have been outlined above. The disadvantage of this option is that there is no guarantee that pipelines would be likely to enforce this provision for the duration of the project. Because pipelines can pass through the higher price to consumers, the producer may be able to renegotiate the contract to take advantage of the potential windfall arising from the dual qualification.

3. *The two-step ratemaking procedures for future applications for planned investment projects.* As presently drafted, the draft final rule requires future applicants for planned investment projects to submit an initial special relief application setting forth a proposed rate computed on the basis of estimated cost data. Even though the final rate is determined on the basis of actual expenditures, the proposed rate serves as a ceiling; the producer is limited to the proposed rate, even if his actual expenditures exceed the estimates which served as the basis for the proposed rate.

When staff accepts this application, the producer may safely assume that when the rate is finally determined he will be authorized to collect the proposed rate, if his actual expenditures prove to be as high as his estimates and they are prudently incurred. But, because the final rate is determined on the basis of actual expenditures, if his actual expenditures are less than the original estimates, his rate accordingly will be less than the proposed rate.

Implicit in this scheme are several problems. An applicant is subject to two review procedures. The scope of inquiry for the first review is necessarily limited by the lesser credibility of estimated

data, and thus the second review, based on actual data, will tend to be more scrupulous. Nevertheless the staff has considerable discretion at both stages to determine the scope and depth of its review so that in some cases an application would be subject to two protracted reviews.

Further, this ratemaking represents a hybrid of the two ratemaking methods traditionally employed by the Commission, *i.e.*, fixed rate and cost-of-service ratemaking. It is comparable to a fixed rate method in that a producer who initially justifies his rate on the basis of estimated costs must bear the loss if his actual costs exceed his estimated costs. However, this ratemaking is also comparable to cost-of-service ratemaking, where a rate is determined on the basis of expenses prudently incurred, so that an applicant realizes no gain if his actual expenditures are less than originally estimated.

As a matter of policy it may be unfair to require a producer to endure the limits of both types of ratemaking. More importantly, this method creates a disincentive to cut costs, *i.e.*, a producer who knows that he is likely to receive the amount of the proposed rate if he actually spends as much as he estimated, first, is encouraged to present initial estimates as high as reasonably possible, and second, is encouraged to spend as much as he estimated, so that he can obtain the full proposed rate.

The following discussion outlines four options, each of which address some of these problems but none of which resolve all of them:

Option A—Employ a "Fixed Rate" Method

Under this scheme, one application would be submitted before commencement of the project supported by cost estimates. Staff would scrutinize the estimates, and upon determining that they are reasonable, set a final rate.

The advantages of this option are that the administrative burdens of a second review are eliminated, and that a producer is encouraged to spend more frugally, knowing that he may reap the benefits of any savings. However, estimated cost and reserve data are far less accurate than actual data, so that a rate computed under this scheme would reflect with considrably less precision the recovery of an appropriate return on investment. Further, this option is more likely to encourage an applicant to overstate his original cost estimates, knowing that they will not be tested against evidence of his actual costs. Also, there would be no opportunity to exclude from consideration costs which are imprudently incurred so that at best, staff could evaluate the proposed expenditures to determine whether they appear to be in line with comparable industry expenditures. Finally, perhaps most importantly, there is no mechanism by which any savings induced by use of this method would be passed on to the pipeline.

Option B—Adopt a Fixed Rate Method, With the Benefit of Any Savings To Be Shared by Producer and Pipeline

Under this approach, an applicant would be subject to two reviews. First, a fixed rate would be determined on the basis of an initial review of estimated costs. After investment has been completed, a review of actual expenditures would be made, and the producer and pipeline would split the difference between the estimated and actual costs.

This method would solve the problem arising under Option A from the failure to provide some means for passing through the cost savings to the consumer. Depending upon the circumstances of the applicant, this method could also provide some incentive to the producer to cut costs. For example, a producer whose actual costs prove less than his estimated costs would be granted a rate equal to the recovery of his costs actually incurred, plus a 15 percent rate of return, increased by half the amount of his cost savings. As a result a producer who spends less in completing a project than originally estimated would receive an actual return on his investment greater than a 15 percent rate of return, while

his return at the higher proposed rate would be limited to 15 percent. If however, a producer is "cash rich" and is willing to make a considerable investment,[6] he may find that the guaranteed 15 percent return is adequate, and perhaps even more attractive when the return is received on a larger dollar amount of investment. In these cases, the producer may still be encouraged to invest up to the full amount of his estimated costs.

This option also presents two noteworthy disadvantages. First, it would require two careful staff reviews so that the estimated costs can be compared with the actual costs. This would result in administrative burdens and delays as considerable as those created by the rule or presently drafted. Second, an applicant is just as likely to overstate his costs so that the resulting increment of savings will be higher.

Option C—Permit the Producer To Recover All Costs Prudently Incurred

Under this option, the rate would be determined on the basis of actual costs prudently incurred. The initial stage of review would involve a staff acceptance of an application upon determining only that the procedures are applicable to the natural gas to be produced from the project,[7] and that the well or platform is an eligible planned investment project.[8] This review would continue to serve as a cutoff point for sunk costs.[9] Also, if the Commission determines that a ceiling on special relief rates should be imposed, provision would be made for the Commission at this initial stage of review to determine whether a rate in excess of the ceiling should be granted.

As an alternative to an initial mandatory staff review, the rule could require at the commencement of an eligible project that a producer notify the Commission that it is undertaking a planned investment project and that it intends to seek a special relief rate for natural gas produced from the project. This notice would serve as the cut-off date for sunk costs (subject, of course, to a determination by the staff at the time of final review that the actual costs included in the application are recoverable). The applicant would be able to seek a preliminary non-binding staff review of his application to provide some guidance as to whether the project is eligible for special relief, the computation is correct, and the proposed expenditures are of the type likely to be found to be prudently incurred. Also, at this time a producer would be entitled to seek Commission authority to collect a rate in excess of the special relief ceiling, a producer who wishes to proceed to invest after giving notice to the Commission without the guidance of an inital staff review would be free to do so.

Under this option, the initial staff review, whether mandatory or optional, would have no effect on the determination of a special relief rate other than to serve as the cut-off date for sunk costs. The only substantive staff review would occur when at the completion of the project a rate based on actual expenditures is determined.

The advantages of this option are that only one thorough review of the application is required, and that rate determination would be more precise, because actual rather than estimated cost data would be considered. In addition, a producer would not have to bear the risk of cost overruns if those costs are prudently incurred. Arguably, the emphasis on actual costs eliminates the disincentive to save implicit in the rule as presently drafted: because the staff would make no evaluation of the costs at the stage of initial review, the producer is not encouraged to believe that expenses prudently incurred up to

[6] Applicants for special relief are contemplating investment in the development of wells, rather than in higher risk activities of exploration. It is not unreasonable to assume that the lesser risk involved in development would make a large investment more attactive.

[7] *I.e.*, that the gas is subject to a maximum lawful price under sections 104, 106 or 109 of the NGPA.

[8] *See*, § 271.1003 of the final rule.

[9] *See*, § 271.1004(a) of the final rule.

that limit will ultimately be approved in determining the final rate.

As a practical matter, however, this difference between this option and present language is largely illusory. As presently conceived, initial staff review and the use of the proposed rate as a ceiling appear to encourage a producer to spend the full amount of estimated costs by suggesting to the producer that he will recover any costs within that limit which are prudently incurred, even though staff acceptance implies no approval of the estimated costs for purposes of determining the final rate. However, the elimination of staff review contemplated in this option will not wholly eliminate the incentive, because that review is merely an audit of the producer's own estimates of the maximum expenditures permissible for the project under the formula set forth in this regulation. Even absent an initial review, a producer who is seeking a return on a large amount of capital will spend to the limit set forth in this regulation. Under this option, as well as under the present language, the only meaningful regulatory limitation on expenditure other than the computation formulae is the requirement that the costs be prudently incurred. In both cases, incentives to save would arise only from the producer's own economic needs.

Option D—Determine a Rate Based on Actual Costs Prudently Incurred with Commission Review of a Proposed Rate To Be Used as a Target

This scheme would operate in essentially the same manner as Option C with two modifications. Initial staff review would involve a review of the proposed rate to determine whether on its face the rate is computed in accordance with the formula set forth in the statute. If so, the proposed rate would serve as a target for the substantive staff review to be undertaken at the completion of the project on the basis of actual cost data.

At the stage of final staff review, the rate would be determined on the basis of actual costs. Staff would have authority to determine a rate which permits the recovery of actual costs prudently incurred up to a specified percentage above the target established by the initial reiew.[10] The Commission would grant a rate substantially higher than the target if it found that the cost overruns were unavoidable. To discourage overruns, the Commission may also wish to require that the producer and the pipeline split the difference between the target and the finally determined rate.

The advantages and disadvantages of this scheme are essentially the same as those described under Option C. The rate would be determined on the basis of the more accurate data of actual costs. Staff review at the initial stage would be insubstantial in contrast with that contemplated in the rule as presently drafted, lessening the administrative burdens and delays.[11] As in the case of Option C, this option would do little to avert the creation of an incentive not to cut costs which is implicit in the rule as presently drafted, and would do nothing to discourage the overestimation of costs.

However, this formulation would work a compromise between the present language and the language of Option C with regard to the treatment of costs prudently incurred in excess of the proposed rate. Under this option, the advantage of the present language would be retained to some extent: a

[10] This would insure that Commission approval would be required only in the case of substantial overruns: for example, where the actual costs are greater than 10% above original cost estimates. As an alternative to selecting a specific percentage figure, the Commission could instead require that the Director forward to the Commission any case in which the cost overruns are so substantial that, [in the Director's discretion], a Commission determination is warranted.

[11] This staff review would necessarily be somewhat more complicated than that contemplated in the initial stage for Option C, where initial review would involve either an optional review or a summary staff determination that the proposed project is eligible for special relief under these regulations, and if necessary, a determination by the Commission as to whether a rate higher than the special relief ceiling is in the public interest.

producer would still be somewhat at risk if his costs exceed the limits of a target, because he would have no assurance that the higher costs would be recovered, and (if he is required to split the difference with the pipeline) he may be required to assume the risk of half the cost overruns. However, this option avoids the draconian penalty for substantial cost overruns imposed by the rule as presently drafted, by providing the opportunity to justify to the Commission the allowance of all prospective costs prudently incurred.

4. *The Selection of an Appropriate Rate of Return for Planned Investment Projects.* The notice of proposed rulemaking sets forth a method for computing a 15 percent rate of return on investment based upon the prior use of a 15 percent return in the 1977 national ratemaking and in recent special relief cases. A number of public comments were received suggesting that a 15 percent return was inadequate to induce investment in light of the markedly increased long-term interest rates that the investor now faces when making investment decisions.

The Commission may be persuaded that the 15 percent return remains the appropriate rate of return for special relief. While it is true that interest rates have increased since Opinion No. 770 was issued, it is important to note that the 15 percent rate was determined as an incentive for high-risk investment in exploration as well as for the lower risk investment costs involved in development. Because special relief involves the return of and on the lower-risk costs of development, the 15 percent rate even in light of increased interest rates should be adequate for the purpose of inducing investment in gas development.

As an alternative, in light of the periodic fluctuations in interest rates, the Commission may wish to provide for the annual indexing of the rate of return in line with the fluctuation in interest rates for long-term government bonds.

Under this scheme, the Commission would establish the 15 percent rate of return as the rate of return applicable to pending applications and to new applications submitted during the current calendar year. At the beginning of each calendar year, the Commission would recompute the rate of return in light of fluctuations in interest rates on long-term Treasury bonds. That rate would be published and would be the rate of return applicable to special relief applications submitted during that calendar year. This periodic adjustment would make the rate of return a more accurate reflection of the capital market conditions at the time the investment decision is made, and would insure that consumers would have the advantage of any decrease in interset rates in future years.

¶ 32,054 Proposed Regulations Under Section 110 of the Natural Gas Policy Act of 1978

45 F. R. 5747 (January 24, 1980).

18 CFR Part 271

[Docket No. RM80-21]

Proposed Regulations Under Section 110 of the Natural Gas Policy Act of 1978

January 18, 1980.

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission gives notice of proposed amendments to the regulations which implement section 110 of the Natural Gas Policy Act of 1978 (NGPA) at Part 271 in the Commission's regulations. These proposals would affect the treatment of State severance taxes in the case of sales of natural gas regulation under section 105 of the NGPA.

DATE: Written comments due by February 19, 1980.

ADDRESS: Send 14 copies of the comments to: The Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, Washington, DC 20426. Reference Docket No. RM80-21.

FOR FURTHER INFORMATION:

Scott E. Koves, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol Street, Washington, DC 20426, (202) 357-8317, or
Teresa Ponder, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol Street, Washington, DC 20426, (202) 357-8151.

I. Introduction

The Commission in Order No. 68, (Docket No. RM80-14) which accompanies this notice of proposed rulemaking, issued final regulations under sections 105 and 106(b) of the Natural Gas Policy Act of 1978 (NGPA). This order gives notice of a proposal to amend the interim regulations under section 110 of the NGPA to provide for the treatment of State severance taxes imposed on gas subject to section 105(b)(1).

The Commission's final regulations under subpart E of Part 271 set forth the procedures for determining maximum lawful prices under section 105 of the NGPA. These prices cover gas sold under existing intrastate contracts and successors to existing intrastate contracts. The maximum lawful price of any section 105 gas depends on the "contract price" applicable on November 9, 1978. If the contract price that was paid (or would have been paid had deliveries occurred) on November 9, 1978, was equal to or less than $2.06, then, pursuant to section 105(b)(1), the maximum lawful price is the lower of the section 102 maximum lawful price or the "price under the terms of the existing contract" as those terms were in effect on November 9, 1978. As provided in § 270.205(b), fixed and indefinite price escalator terms in the existing contract on November 9, 1978, can operate to increase the price up to the new natural gas price. Section 105(b)(1) is implemented by § 271.502(a) of the final regulations.

If the contract price that was paid (or would have been paid had deliveries occurred) on November 9, 1978, exceeded $2.06, then, pursuant to section 105(b)(2), the maximum lawful price is the higher of the section 102 maximum lawful price, or the contract price actually charged on November 9, 1978, escalated each month by the inflation adjustment factor applicable to such month. (*See* NGPA section 101(a)).

This proposed rule applies to natural gas subject to section 105(b)(1) of the NGPA and would prescribe the extent to which State severance taxes may be

recovered by the seller both under that section and section 110 of the NGPA.

II. Discussion

A. Determination of "Contract Price" and "Price Under the Terms of the Existing Contract"—Section 105

The Commission addressed the severance tax issue in Order No. 68, in which is explained:

> The term "contract price" in section 105 is used to determine whether a contract qualifies under paragraph (b)(1) or (b)(2) and to determine the maximum lawful price in paragraph (b)(2) * * *. We believe that the word "price" in the definition of "contract price," as well as the phrase "price under the terms of existing contract" means the total amount of proceeds paid by the purchaser to obtain the subject gas. Therefore, the term "price" would include all proceeds paid or payable to the seller even if specifically earmarked as reimbursement for State severance taxes or production-related costs.
>
> Consequently, in determining the maximum lawful price under section 105 the total proceeds paid or payable on November 9, 1979, are to be compared to $2.06. If the total proceeds exceeds $2.06, then section 105(b)(2) applies. If not, then section 105(b)(1) applies.
>
> If section 105(b)(2) applies, then the total proceeds paid or payable on November 9, 1978, are used as the base to which the inflation adjustments of section 105(b)(2)(B) are applied. If section 105(b)(1) applies, then the total proceeds receivable under the contract may increase pursuant to the terms of the contract in effect on November 9, 1978, up to the section 102 level. [mimeo pages 6–7]

The Commission also examined the question of whether State severance taxes should be subtracted from the section 105 contract price. It determined they should not, and stated that the further question "as to whether the seller may add the amount of any such taxes borne by him to the section 105 ceiling price under section 110 of the NGPA and under § 271.1102 of the Commission's regulations" would be addressed in this separate rulemaking proceeding.

Section 271.1102 of the Commission's interim regulations as it is presently written, speaks in terms of making additions to maximum lawful prices, without specifically referring to the section 105 price. Several comments on the interim regulations asserted that the Commission must amend § 271.1102 to clearly permit the addition of State severance taxes borne by the seller to the section 105 ceiling price. The Commission is tentatively of the view that it should in most cases decline to extend the provsions of § 271.1102 to section 105(b)(1) because there is an essential difference between the nature of the section 105(b)(1) price and other maximum lawful prices in Title I.

While most maximum lawful prices are tied to one specific ceiling price established by Congress, the maximum lawful price for section 105(b)(1) references negotiated prices established by the parties to intrastate contracts in existence on November 9, 1978. These contracts number in the thousands. Accordingly, there are potentially many thousands of individual maximum lawful prices under section 105(b)(1) of the NGPA. Moreover, many of these contracts contain provisions under which the seller clearly agrees to pay all severance taxes. Other provide that the buyer agrees to pay all severance taxes. Other contracts may provide that buyer and seller share the obligation to pay either existing or increased severance taxes. Still others may be silent as to severance taxes. However, in all cases, we believe it is reasonable to presume that when the seller negotiated the contract, he took into consideration the amount of severance tax for which he was to be liable.[1] The total proceeds to be received under the contract, therefore, are presumably sufficient to repay the seller for all severance taxes he may be obligated to pay. Because the section 105(b)(1) price is based on this consideration, it is our tentative view

[1] Severance taxes are among many costs of providing service that a producer will take into consideration when he negotiates price terms.

that no additional allowance under section 110 is necessary to allow the seller to "recover" severance taxes paid by him because the seller is already recovering all such taxes in the proceeds he receives.

In considering this issue, we would propose to apply section 110 in the manner which is most consistent with Congressional intent that price regulation of the intrastate market reflect the prices and provisions originally bargained for.[2] Assuming the seller is already reimbursed for State severance taxes under the contract, an additional adjustment under section 110 would arguably permit double recovery of State severance taxes. Permitting such double recovery of State severance taxes would under this view be inequitable and would be inconsistent with Congressional treatment of the intrastate market. Therefore, we do not propose to amend § 271.1102 as commenters suggest. In Order No. 68, the Commission has already amended the definition of "contract price" in § 271.504(a) to clarify that "contract price" includes State severance taxes levied on the sale and which are either borne by the seller or reimbursed by the purchaser. A similar amendment was made to the definition of "price under the terms of the existing contract" in § 271.504(b). In this notice of proposed rulemaking we would also add a new paragraph (c) to § 271.1102 which clarifies that ceiling prices under section 105 include reimbursement for certain State severance taxes and which limit the State severance taxes which under section 110 may be added to the section 105 ceiling price.

The Commission's proposed rule limiting the section 110 allowance for State severance taxes would prevent "double recovery" of severance taxes borne by the seller. However, under the proposed rule, if the section 105(b)(1) maximum lawful price constrains the seller from collecting the full price specified under the terms of his contract (as in effect on date of enactment of the NGPA), then, to the extent he is so constrained, he may collect the allowance for State severance tax under section 110.

The proposed rule recognizes that simply because a seller's contract price on date of enactment might have been sufficient to ensure payment of all State severance taxes levied on the sale, there may be cases in which he will not be permitted to collect the negotiated "contract price." For example, if the seller's contract provided for an indefinite price escalator increase from $1.50 to $5.00, effective December 1, 1978, his ceiling price under section 105(b)(1) for December 1978 would only be $2.078. His total proceeds could not lawfully exceed that amount.

The following amendment to § 271.1102 will permit a seller under an existing intrastate contract subject to section 105(b)(1) to fully recover State severance taxes levied on the sale of natural gas subject to such contract:

(c) Under § 271.502(a) of Subpart E, the price under the terms of the contract (as those terms were in effect on November 8, 1978) is deemed to be sufficient to recover State severance taxes (whether borne by the seller or reimbursed by the buyer). State severance taxes may not be recovered under this section except to the extent the price under the terms of the contract as those terms were in effect on November 8, 1978, exceeds the maximum lawful price specified for new natural gas (Subpart B of Part 271) in Table 1 of § 271.101(a).

However, we do not believe that the same treatment of severance taxes can be implemented in the case of sales under section 105(b)(2) contracts because of a fundamental distinction between section 105(b)(1) and (b)(2).

[2] This approach is in accord with our position disallowing the shifting of production-related costs to the purchaser in sales of natural gas subject to existing intrastate contracts. In the Preamble to the Interim Regulations (43 F.R. 56448) we noted, "It would be contrary to the intent of Congress to permit a change in such prices and terms that would have the effect of increasing the total costs borne by the purchaser for acquiring the very same commodity as he was acquiring for a lower price before date of enactment.

Section 105(b)(1) focuses on the terms of the contract on November 9, 1978. Presumably these were bargained for on an arms-length basis prior to enactment of the NGPA. In effect, each contract which falls under section 105(b)(1) imposes an individual set of pricing regulations superceded only in the event that the price under such terms exceeds the section 102 ceiling price (*See*, section 105(b)(1)(B)). Ceiling prices under section 105(b)(1) are *continuously* circumscribed by the pre-NGPA negotiated provisions of the contract, which, with certain exceptions noted above, provide a continuous recoupment of all existing State severance taxes borne by the seller.

This pricing mechanism is to be contrasted with that of section 105(b)(2). Under section 105(b)(2), while the negotiated "contract price" on date of enactment of the NGPA forms the base to which inflation adjustments are later applied, that is the one and only occasion on which the terms of the contract affect the ceiling price.[3] After the date of enactment, as is the case with all other Title I ceiling prices (except section 105(b)(1)(A)), numerical price limitations are mechanically applied to the previous month's ceiling price. All Title I ceiling prices (except section 105(b)(1)(A)), are arrived at in essentially the same way: a base price per MMBtu on a given date is adjusted upward each month with inflation related increments. For example, after December 1, 1978, all ceiling prices under sections 103, 104, 106(a), 106(b)(1), 109 and 105(B)(2) escalate upward at exactly the same rate of increase.

Based on these considerations, we find no practical difference between section 105(b)(2) and other Title I ceiling price sections (except 105(b)(1)) with respect to the method of computing ceiling prices. As such, we also can perceive of no reason why the recovery of State severance taxes under section 110(a)(1) should be handled differently in the case of section 105(b)(2) than the other Title I ceiling price provisions. Accordingly, as a general rule, the price under a section 105(b)(2) contract would be permitted to increase above the section 105(b)(2) ceiling price to the extent necessary to recovery State severance taxes borne by the seller. *See* § 271.1102(a).

However, because our policy respecting the treatment of State severance taxes is only a proposal at this juncture, we specifically invite comments on this issue in the context of both sections 105 and 106(b).

There may be circumstances to which the proposed § 271.1102(c) would not apply and which, due to special hardship, inequity, or unfair distribution of burdens, it would be appropriate to permit a section 110 allowance (or other form of relief) for severance taxes paid by the seller under a section 105 contract. However, these matters are more properly considered in the context of an application for an adjustment in a section 502(c) proceeding.

The Commission also recognizes that some gas subject to section 105 pricing may subsequently receive a determination of eligibility under section 102, 103, 107 or 108, and, contract permitting, may receive a maximum lawful price under one of those sections, to which severance taxes may then be added. Once gas has become eligible to move into an "incentive" pricing category, the contract price or terms as of November 9, 1978, are no longer instrumental in determining the maximum lawful price and the gas becomes eligible for all of the benefits Congress intended to give other Title I gas. Because the base prices for other Title I gas were not based on private negotiations and therefore cannot be assumed to provide compensation for individual severance taxes (with the exception of Permian Basin gas, see § 271.102(b)), the proposed rule would permit the addition of State

[3] Except of course, that the contract terms always override ceiling prices if the contract does not permit the collection of the ceiling price. See section 101(b)(9) of the NGPA. This applies to *all* ceiling prices, not just those under section 105.

severance taxes. Therefore, contract permitting[4], gas qualifying under sections 102, 103, 107 or 108 could be sold at a higher base ceiling price and the applicable severance tax allowance may be added to that price.

B. Contract Modification

In Order No. 68, at page 14, we noted:

Several comments were also received which suggested that, in any case in which an existing intrastate contract provides that the purchaser shall reimburse the seller for 85 percent of increased severance taxes, and in the event of such a tax increase, the parties should be allowed to amend the contract to provide for 100 percent reimbursement of such taxes. Section 271.1102, unless modified in accordance with the proposed rule which accompanies this final rule, permits full recovery of State severance tax. Section 270.205(c) makes it clear that the NGPA does not prohibit contract modifications necessary in order to collect maximum lawful prices.

However, a different result would be reached under the proposed rule. If the contract is subject to section 105(b)(1) of the NGPA, the parties may not increase the price under the terms of the contract as those terms were in effect on November 9, 1978. If section 105(b)(2) applies, then the amendment may not result in a price in excess of the ceiling imposed by paragraph (b)(2)(B)(ii) of section 105, plus applicable section 110 allowances. As long as contract amendments do not cause the price paid to exceed the applicable ceiling price, the parties may allocate the obligation to pay for such taxes in any manner they wish.

III. Summary of Amendments

The proposed rule would make the following amendments to the Commission's rules:

Section 271.1102 would be amended to explain the treatment of State severance taxes with reference to section 105(b)(1) gas.

IV. Public Procedures and Effective Date

The Commission requests comment on the proposed rule, and specifically requests comment on whether § 271.1102 should prohibit any allowance for State severance tax under section 110 of the NGPA with respect to all natural gas subject to sections 105(b)(1), 105(b)(2), and 106(b). The Commission also requests comment on whether provision should be made for special treatment of increases in State severance taxes after November 9, 1978. In addition, comment is requested on the issue of the relationship between the ceiling price for intrastate rollover contracts and the allowance for severance taxes for the expired existing intrastate contract, as well as the general question of the interaction between the section 105 and 106(b) ceiling prices and the allowance for State severance taxes under section 110.

Interested persons may submit comments by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before February 19, 1980. Each person submitting a comment should include his name and address, identify Docket No. RM80-21, and give reasons for any recommendations. An original and 14 conformed copies shoud be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

The Commission intends to hold a public hearing on the proposals, as required by section 502 of the NGPA. The date and location of such hearing will be announced shortly. The

[4] See section 101(b)(9) of the NGPA.

regulations proposed in this notice shall not become final until the Commission has had an opportunity to receive oral presentation of relevant data, views and arguments.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Department of Energy Organization Act, 47 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

The Commission proposes to amend § 271.1102, as set forth below. Such proposed amendments are proposed to become effective April 1, 1980.

By the direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 271.1102 is amended in paragraph (a) by deleting the phrase "paragraph (b)" and inserting in lieu thereof the phrase "paragraphs (b) and (c)," and by adding a new paragraph (c) to read as follows:

§ 271.1102 State severance taxes.

* * * * *

(c) Under § 271.502(a) of Subpart E, the price under the terms of the contract (as those terms were in effect on November 9, 1978) is deemed to be sufficient to recover State severance taxes (whether borne by the seller or reimbursed by the buyer). State severance taxes may not be recovered under this section except to the extent the price under the terms of the contract as those terms were in effect on November 9, 1978, exceeds the maximum lawful price specified for new natural gas (Subpart B of Part 271) in Table 1 of § 271.101(a).

¶ 32,055 Revised Requirements for Filing Changes in Electric Rate Schedules and for the Preparation and Submittal of Supporting Data

45 F. R. 11817 (February 22, 1980); 45 F. R. 13122 (February 28, 1980).

18 CFR Part 35

[Docket No. RM79-64]

Revised Requirements for Filing Changes in Electric Rate Schedules and for the Preparation and Submittal of Supporting Data

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to revise that portion of its regulations governing the filing of changes in the electric rate schedules of public utilities under Part II of the Federal Power Act. The Commission proposes the revision to help expedite the disposition of electric rate change cases. The revised § 35.13 would consolidate the data expressly required to be filed under the existing § 35.13 with the data routinely requested of a utility following submittal of the original rate change application. By obtaining full and detailed cost of service information earlier in the ratemaking process, the Commission expects to arrive at quicker decisions about just and reasonable electric rates. Certain data required to be filed under the revised § 35.13 are not presently filed in rate change applications. The proposed rule also raises the dollar threshold for filing abbreviated cost of service information. The effect of the proposed rule will be to help minimize decisional delays in the ratemaking process.

DATES: Written comments are due no later than Monday, April 14, 1980.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Filed comments should reference Docket No. RM79-64.

FOR FURTHER INFORMATION CONTACT: Leo T. Markey, Director, Division of Rates and Corporate Regulation, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 376-9195 or James Hoecker, Division of Regulatory Development, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Issued February 15, 1980.

The Federal Energy Regulatory Commission (Commission) gives notice that it proposes to revise its regulations governing the filing of changes in the electric rate schedules of public utilities under the Federal Power Act. The Commission takes this action in the belief that revision of § 35.13 will contribute to the general goal of more expeditious disposition of wholesale rate change cases. The proposed revision consolidates the data expressly required to be filed under existing § 35.13 with the data routinely requested following the initial application for a change in a rate schedule. Certain data required to be filed under the revised § 35.13 are not now filed in rate change proceedings.

I. Background

On September 26, 1963, the Commission's predecessor agency, the Federal Power Commission (FPC), issued Order No. 271[1] that required the filing of cost of service statements in support of major electric rate increase applications. Order No. 271 also established cost of service data statements A through O.[2] The FPC considered these statements adequate to

[1] 30 FPC 850, 28 *Fed. Reg.* 10573 (October 2, 1963).

[2] Statement P, dealing with rate design information, was added by Order No. 537, issued October 9, 1975, 40 *Fed. Reg.* 48673 (October 17, 1975).

provide information sufficient for threshold decisions with respect to further investigation of any of the then infrequent wholesale rate increase proposals. In a major subsequent amendment to § 35.13, the FPC required cost-supporting data for each of two periods as criteria for just and reasonable rates. Period I was created as a historical twelve-month period of actual data and Period II constituted a twelve-month test period for estimated cost data.[3] The use of estimated Period II data was devised to help utilities keep up with inflation in the costs of operation.

In 1976, the FPC issued Administrative Order No. 157 which established "top sheet procedures" in natural gas pipeline and public utility rate cases.[4] The top sheet is a summary cost of service schedule prepared by staff to facilitate the settlement process by expediting the dissemination of staff's analysis of cost of service information.

The regulations in this docket are proposed in response to the increased frequency and dollar amounts of electric rate increase applications in the past several years. Since staff has frequently found it necessary to supplement the information supplied in the original filing by requesting additional data from the filing utility, the recent volume of rate change applications has made the use of data requests an increasingly frequent and time-consuming part of rate proceedings.

The existing § 35.13 does not require detailed cost of service information for rate change applications which would amount to less than $50,000 annually. That threshold was established in an effort to avoid an unnecessary burden on utilities filing for moderate rate increases; however, fewer applications now qualify under the threshold for the alternative of submitting only summary cost of service data under § 35.12(b)(2) and (5). Because inflation has led to requests for comparatively larger increases in rates, the Commission proposes to raise the threshold to permit applicants for rate changes of less than $200,000 annually to provide only summary data, if those data sufficiently support the application. Moreover, if all wholesale customers in the affected rate class consent to the rate increase, the threshold below which a utility may file less detailed data is proposed to be raised to $1,000,000.

The revised § 35.13 addresses other difficulties posed by the present regulation, such as the lack of clear guidelines for preparing and submitting rate change applications and cost of service data statements. The Commission has found that this weakness has resulted in rate change filings that are not sufficiently detailed and explanatory to allow efficient prehearing review. The objective of the proposed rule is to clarify the filing requirements and to present in one place a range of data usually requested during a rate change proceeding. Although the revised § 35.13 is more detailed than the existing section, the Commission is not requiring the filing of substantially more data than are presently required for its proceedings. The Commission Chairman has recently made the point, in a report to the Congress, that the ratemaking process requires the compilation and organization of certain kinds of data sooner or later and "the sooner it is done, the greater the benefit to everyone involved in the regulatory process."[5] This docket is created to help eliminate decisional delay.

The Commission anticipates that the revised § 35.13 would benefit all participants in Commission rate change proceedings in the following ways. First, the amount of time required for the prehearing disposition of rate change applications set for hearing will be

[3] Order No. 487, issued July 17, 1973, 50 FPC 125, 38 *Fed. Reg.* 1967 (July 26, 1973).

[4] Issued April 1, 1976, 41 *Fed. Reg.* 15080 (April 9, 1976).

[5] Charles B. Curtis, *Decisional Delay in Wholesale Electric Rate Increase Cases: Causes, Consequences and Possible Remedies*, January 23, 1980, at 72.

reduced. The regulation would require that information routinely needed for the processing of an application, but heretofore retrieved by data requests subsequent to the initial filing of an application, be provided as part of the original filing. Efficient collection of cost of service data will also be facilitated by requiring the transfer of important information currently provided only in work papers to specific statements where it is more readily accessible. Although the Commission or its staff would not be precluded from making any additional requests for information that particular cases may require, it is expected that the savings of time between the filing for a change in rates and approval of the new rate will be substantial. The proposed revision also promotes the objectives of Order No. 157 that established topsheet procedures by requesting cost of service data in a tabular form that will facilitate computer programming by Commission staff for more rapid analysis and distribution. The revised regulation also seeks to incorporate filing requirements that reflect generic decisions adopted by the Commission in specific cases.[6]

A. *Cost of Compliance.* Participants in the technical conferences (discussed below) that were held to review a staff draft of this proposal were invited to offer estimated cost information regarding compliance by utilities with both the present and proposed § 35.13. The most complete response by a participant reported a survey of seven utility companies.[7] There was considerable variation among the seven reporting companies as to the estimated costs to file a major rate increase under current regulations. The average estimated cost was $140,000. The companies estimated an average additional $40,000 to respond to discovery data requests, for a total of $180,000 per filing.

The survey pertained only to new cost of service Statements AA to AT in paragraph (h). Compliance with the proposed regulations through Statement AT was estimated to cost on average about $100,000 more than current costs of $140,000 for the first compilation and submittal of data. There would then be a recurring cost for subsequent filing of about $40,000 more than the current $140,000, for a total of $180,000 per filing to maintain and submit data under the new system. Although the survey did not attempt to make any precise reconciliation between costs under present and proposed regulations, it appears that the $40,000 for responding to present discovery requests is roughly equivalent to the estimated additional recurring cost of filing under the proposed new regulations.

The staff believes that a substantial amount of the estimated additional costs attributed to this rulemaking were the result of the original proposal to require monthly data for all rate base items and for deferred tax balances by function. This proposal makes these requirements less stringent and the estimated cost of compliance would probably be little, if any, greater than the cost is under the current regulations, if the costs of discovery under the present system are added in. This is especially true for those utilities whose rate filings already demonstrate well developed cost support.

The Commission solicits comment and supporting data about the cost of submitting cost of service information under the existing § 35.13, the cost of responding to related discovery data requests in cases set for hearing under the existing § 35.13, and the relative cost of submitting information under the revised § 35.13 proposed in this docket. Information on the cost of filing under the proposed rule should be supplied

[6] Order No. 555, issued November 8, 1976, 41 *Fed. Reg.* 51392, alowed pollution control and fuel conversion construction work in progress to be included in rate base (Account 107). This is reflected in Statement AG. Order No. 561, issued February 22, 1977, 42 *Fed. Reg.* 9161, established maximum rates to be used in computing AFUDC and provided accounting and reporting requirements. This is reflected in Statement AO.

[7] Technical Conference on Docket No. RM79-64, Revison of § 35.13 of the Commission's Regulations, Transcript of October 19, 1979, at 147 (Central Files, Federal Energy Regulatory Commission).

both in terms of the initial cost of collecting, organizing, and submitting the data for the first time and in terms of the continuing costs of compliance for subsequent rate change filings. Commenters are asked to identify specifically the portions of the revised cost of service statements that would result in any significant increases in costs of utilities.

B. *Technical Conferences.* Prior to issuing a Notice of Proposed Rulemaking in this docket, the Commission staff held four technical conferences, October 4, 5, 18 and 19, 1979, in Washington, D.C. (44 FR 53538, September 10, 1979). Twenty-four persons were invited to discuss a draft of this rulemaking. Questions and comments were also welcomed from the public. The participants included representatives of public utilities and intervenor groups experienced in the electric ratemaking process and Department of Energy and Commission personnel. Among the major contributions of the conferences to the evolution of this rulemaking are the following:

1. The requirement of the thirteen-figure averages for various plant values and depreciation is now more narrowly applied. Averages for the beginning and end of the year or test period were deemed sufficient for other plant and depreciation components of rate base.

2. Certain data are apparently not always available according to major functions of plant. To avoid requiring added studies by the utilities, functionalized data is requested for certain statements only if they are available.

3. Statement BC, reliability data, is clarified as an informational data collection statement only, not a requirement to develop objective standards for power supply reliability.

4. Form 61, a form on which the utilities would have provided most cost of service information in a computer compatible format, is eliminated because of the burdens envisioned by utilities. In its place is a tabular summary of data (Statement BJ) that will facilitate ready access to the data and ensure its completeness.

5. The seven-month rule governing how old Period I data is permitted to be is altered to allow greater use of calendar year data and to avoid the large number of mid-year rate filings encouraged by the current rule.

6. The use of abbreviated cost of service information will be permitted for rate changes that amount to less than $200,000, an increase from the current $50,000, or for rate changes of less than $1,000,000 if customers consent to the change. In addition, Period II data is not required for increases of $1,000,000 or more if wholesale customers consent to the rate change.

C. *Advisory Committee Recommendations.* The proposed regulations will implement the bulk of the relevant recommendations of the Subcommittee on Filing and Substantive Regulatory Requirements of the FERC Advisory Committee on Rules of Practice and Procedure stated its report of October 2, 1979. Those recommendations generally tend to parallel the changes in existing § 35.13 that were made in the staff draft of this rulemaking or that were suggested by technical conferees.

II. Discussion of the Proposed Regulation

A. *General filing requirements.* Paragraphs (a) through (g) of the proposed regulation set forth the basic requirements for submitting and supporting an application for a change in an electric rate schedule that must be filed with the Commission. The procedures and substantive requirements in these paragraphs are substantially the same as those in existing § 35.13. The provisions have been restructured, however, to sharpen the focus of the regulation on what material must be filed and by whom, the size or nature of the proposed rate change, and the kind of test period data needed to justify the proposed rate change.

The proposed § 35.13 seeks to reorder the basic filing requirements found in existing paragraphs (a), (c), and (d), and portions of (b). Proposed paragraph (a) specifies which provisions apply to

certain applicants for a rate change, depending on the nature of the proposed change. Proposed paragraph (b) requires of all filing parties the submission of the same variety of general information as required under existing paragraph (a). Similarly, the standard information on the effects of the proposed rate change is included under proposed paragraph (c).

The present requirement for comparative revenue date for the 12 months before and 12 months after the proposed effective data is proposed to be modified to permit comparative revenues to be reported for the historical (Period I) and estimated (Period II) 12-month cost of service periods. This will eliminate unnecessary preparatory effort for a filing. However, this change in the basis of comparative revenue data will necessitate conforming or compensation changes in § 36.2 of the Commission's regulations, pertaining to filing fees.

The requirement that utilities file specific historical and estimated cost information to substantiate the justness and reasonablness of the proposed rate is revised for clarity in proposed paragraph (d).

Paragraph (d) contains an important change in the Commission's definition of "Period I." The requirement that Period I end not earlier than seven months prior to the filing date is modified. It is proposed that the data for the last month of Period I be no older than 15 months on the date of the rate change filing, thereby permitting more extensive use of calendar year data for Period I. Modification of the "seven-months rule" may also decrease seasonal peaking of the Commission workload seven months after the close of the last calendar year.

The proposed change in the definition of Period I is accompanied by a revised definition of Period II. The estimated cost of service data for the twelve months of Period II, when required, would follow the end of Period I data.

However, Period II may begin not earlier than twelve months before the proposed effective date of the rate change nor later than the proposed effective date. Under this approach, Period II estimated data could be largely historical at the time of filing, particularly if the Period I data is as old as permitted under the new definition of Period I. For this reason and because the Commission does not otherwise want to inhibit the use of calendar year estimated data, the use of an alternative Period II definition was considered by the Commission on February 6, 1979. The tweleve months of this alternative Period II would be required to begin not later than three months after, nor more than nine months before, the date on which the new rate is proposed to become effective. The Commission solicits comments on the relative merits of the definition of Period II provided in the proposed rule and the alternative definition of Period II. Commenters should specifically address the effect of each definition on the ability of a filing utility to use calendar year data and any consequences the either definition might have on the concentration of filings during certain times of the year.

Several miscellaneous provisions set forth throughout the existing regulation are brought forward and placed before the extensive cost of service statements provision. Paragraph (e), describing the filing utility's burden of proof and the treatment to be given testimony and exhibits, is derived from existing § 35.13(b)(5). Existing paragraph (c) is revised and relocated as paragraph (f); it informs an applicant not required to support a rate change proposal with cost of service information that the Commission may request such information by letter, if such data are necessary for evaluation of the proposal. Proposed paragraph (g) is comparable to paragraph (d) in the existing § 35.13. Paragraph (g) states that a filing utility must conform cost of service filings under § 35.13 to requirements of general applicability and all applicable Commission orders.

The most important filing provisions may be summarized as follows:

A filing utility, whether filing for an increase in rates individually or as a

party concurring in coordination and interchange agreements, must file the information required in paragraphs (b), (c), (d), (e), and (h), except under any of three special circumstances. Under proposed paragraph (a)(2), utilities proposing rate increases that would amount to less than a specified amount, involve short-term service, or pertain to integral parts of a coordination and interchange aggreement may choose to submit summary information to support a proposed rate increase. Changes in rates less than the threshold amount may be supported by full cost of service information, if the utility so chooses. Likewise, rate changes that do not result in a rate increase or changes that result from changes in delivery points, delivery voltage, or similar changes in service need be supported only by general information in paragraphs (b) and (c), subject to any necessary data requirements imposed by the Commission. For rate changes which are proposed in coordination and interchange rate schedules, a representative may be designated by the parties to the transaction to file the required information.

A filing utility that is required under paragraph (a)(1) to submit the detailed cost of service statements described in paragraph (h), or that elects to submit such data, must use historical data for "Period I," which is defined in paragraph (d). If the proposed rate change would have amounted to one million dollars or more in revenue during Period I, the utility must also submit "Period II" data which is estimated for a twelve-month period after the end of Period I that begins not later than the proposed effective date of the rate change and not earlier than twelve months before the proposed effective date. The utility provides supporting data for both periods in the paragraph (h) statements.

If the proposed rate increase would amount to less than one million dollars, the filing utility may elect not to file Period II data and instead file only Period I data, in which case Period I will be the criterion for the just and reasonable rate. In other words, Period I will be the test period. In this case, however, the Commission will permit adjustment of the Period I information which otherwise is not updated to reflect changes in revenues and costs. This practice has been permitted under the current regulations. If Period II data is filed, it will be the test period and such estimated costs must be supported by the utility's work papers. The requirement to file Period II data is the same as in the existing § 35.13. However, the Commission now proposed to modify this requirement to excuse the filing of Period II data if all wholesale customers in the affected rate class have consented to the proposed rate increase.

B. *Cost of service statements.* Revision of an elaboration on the cost of service statements are the major objectives of this rulemaking. The new statements are contained in paragraph (h).

The existing § 35.13(b) contains 17 cost of service statements, A through P. The Commission proposed to reorder and expand the statements. Proposed paragraph (h) contains 37 cost of service and supporting statements, AA through BL in paragraphs (h)(1) through (h)(37). The increase in the number of statements does not represent a substantial increase in information requested beyond that required in existing § 35.13 and routinely obtained by data requests. The proposed statements are more precise and descriptive in their delineation of what is needed to support a proposed rate increase. With the exception of parts of Statements AV (Rate of Return Claimed) and BB (Allocation Demand and Capacity Data), the first 35 statements are intended to be data reports. The last two statements (Statements BK and BL) are designed to reflect analytical interpretation of all elements of cost of service data.

Although Statement BJ is new it is simply a concise summary of specific data taken from the other data reporting statements. This information gathered from the various cost of service

statements will further facilitate Commission decisionmaking when integrated into staff's computerized cost of service program.[8] In addition, an applicant that prepares Statement BJ will be rechecking the information contained in the statements from which the data is taken. This statement will, therefore, assist in minimizing deficient filings and the consequent revenue loss.

Statement BK is also a noteworthy revision to several of the cost of service statements. It consolidates related information now provided under three statments: Statement L on overall cost of service; Statement M on allocated cost of service; and Statement N on comparisons of cost of service. Statement BK provides for the filing utility to indicate its total cost of service and that part of the cost allocated to the wholesale services subject to the proposed change in rates.

Statement BL carries forward the requirements of present Statement P in which the filing utility must justify the proposed rate design in terms of allocated cost and other considerations. Statement P was added to the existing § 35.13 in 1975 by Order No. 537 (*see* Footnote 3). The current interest in marginal cost pricing concepts and in time-of-use rate differentiation make it appropriate to recount the policy set forth in the preamble of that order, which policy is also carried forward in Statement BL in this rulemaking:

> The Federal Power Act establishes criteria for this Commission in the exercise of its rate regulatory authority. Rates must be just and reasonable, non-preferential and non-discriminatory. We believe that it would be appropriate for the Commission to consider the extent to which application of marginal cost pricing principles will result in rates which conform more closely with these criteria while at the same time achieving the objectives outlined above. The record before us in this proceeding, however, does not provide a sufficient basis to determine the feasibility of applying marginal cost pricing principles to the design of rates subject to our jurisdiction, particularly rates charged to distributor systems for firm power. *Issuance of the subject filing requirements will not prejudice any party's rights, including those of our staff, to offer innovative rate design proposals through evidentiary presentations.* Indeed, we believe that this matter should be examined by all electric systems with a view to determining whether alternate pricing mechanisms, particularly those based on marginal cost principles, for wholesale sales subject to the jurisdiction of this Commission would be economically sound as well as in accordance with statutory requirements. We note that at the present time a number of studies of rate design alternatives are in progress. We would welcome the introduction into evidence in rate proceedings before this Commission materials that become available from these studies to assist us in reaching judgments that are in the public interest. [Footnote omitted.] [Emphasis added.] 54 FPC at 1537–1538.

Statement BL is not therefore intended to discourage marginal cost pricing or the filing of time-of-day rates.

Certain other statements in paragraph (h) are of special interest.

Statement AF identifies specific internal sources of capital which should be considered as potential deductions from the otherwise required net original cost rate base used to establish capital costs. Statement AG identifies capital requirements other than working capital that should be considered as potential additions to net original cost rate base. It is important to note that Statements AF and AG identify as potential rate base deductions or additions certain information that in recent experience have been infrequently considered for such purposes. The Commission is placing the information in the following balance sheet accounts in the cost of service statements so that its significance for rate base determinations may be assessed.

Account No. and Description

252—Customer advance for construction.
255—Accumulated deferred investment tax credits (eligibility dependent upon applicant's election under law).

[8] The Electric Cost of Service (ECS) Program developed by the Office of Electric Power Regulation was issued in May 1978 and is available to the public on request. It includes a user's manual.

Account No. and Description

261—Property insurance reserve.
262—Injuries and damages reserve.
263—Pensions and benefits reserve.
265—Miscellaneous operating reserves.
182—Extraordinary property losses.

Statement AD establishes reporting patterns for many of the other statements. It requires reporting of an average for thirteen monthly balances (the beginning of the first month and the end of each month of a period) for all production and transmission plant to be claimed in the basis of capital costs. It also establishes definitive criteria for selection by the filing utility of subfunctional categories of major functional classifications of electric plant in service which categories are recognized throughout the statements. The statement also sets forth the instances in which general, intangible, common, and other plant categories need not be divided into subfunctional categories.

Statement AL has been drafted to refer to proposed § 35.24 set forth in the Commission's Notice of Proposed Rulemaking, issued June 7, 1979 in Docket No. RM79–49. (44 FR 33410, June 11, 1979.) The proposed § 35.24 establishes a formula for calculating the working cash allowance of working capital. The Commission's policy during the pendency of the rulemaking is stated in *Carolina Power and Light Company*, Opinion No. 19–A, issued February 21, 1979 (Docket No. ER76–495):

> Where a fully developed and reliable lead-lag study is available in the record, we will utilize that study to determine the working capital allowance. Where a study meeting these criteria is not available we will continue to apply the 45-day convention. However, two adjustments will be made in the latter instance, provided the information is available. Fossil fuel expense has come to represent a major expense item for many utilities and, therefore, a substantial component of the O&M expenses. Where this is the case, and the actual lag in the payment for fossil fuel is known, the amount thereof will be substituted as an adjustment to the results otherwise attained by the 45-day rule. Second, where an adjustment for fuel expense lag is made, a further adjustment will be performed, as an add-on to the results under the formula, to recognize the increased importance to the utilities of purchased power expense. This item has not heretofore been comprehended within the operation of the rule. In our opinion, the combination of these two adjustments with the formulary method will produce a more accurate reflection of the utility's actual operating cash needs.

Statement AV (Rate of Return) is similar to present Statement G. However, Statement AV requires more information dealing with the cost of capital. This information is required in prehearing discovery and its inclusion in Statement AV is intended to minimize the need for data requests.

Several statements are designed to obtain in detail the information described in current statements only in general terms. Examples of this elaboration can be found in proposed Statements AF, AG, AP through AT, BE, and BF.

Statement AX is designed to elicit information not generally requested on a routine basis. Statement AX would provide information about rate change cases which the filing utility might have pending before another regulatory body or agency, especially with respect to revenues collected subject to refund.

The following table illustrates the relationship of the existing and revised statements for § 35.13:

Proposed	Description	Presently acquired through existing statements or prehearing discovery *
AA	Balance Sheets	A
AB	Income Statements	B
AC	Retained Earnings Statements	C

Proposed	Description	Presently acquired through existing statements or prehearing discovery *
AD	Cost of Plant	D
AE	Accumulated Depreciation and Amortization	E
AF	Specified Deferred Credits and Operating Reserves	Discovery
AG	Specified Plant Accounts and Deferred Debits	M, L, E1
AH	Operation and Maintenance Expenses	H
AI	Wages and Salaries	M, Discovery
AJ	Depreciation and Amortization Expenses	I
AK	Taxes Other than Income Taxes	K, Discovery
AL	Working Capital	F, Discovery
AM	Construction Work in Progress	Discovery
AN	Notes Payable	Discovery
AO	Allowance for Funds Used During Construction	Discovery
AP	Federal Income Tax Deductions—Interest	J
AQ	Federal Income Tax Deductions—Other than Interest	J
AR	Federal Tax Adjustments	J
AS	Additional State Income Tax Deductions	J
AT	State Tax Adjustments	J
AU	Revenue Credits	M, Discovery
AV	Rate of Return	G, Discovery
AW	Cost of Short Term Debt	Discovery
AX	Other Recent and Pending Rate Changes	Discovery
AY	Income and Revenue Tax Rate Data	Discovery
BA	Wholesale Customer Rate Groups	M, N, Discovery
BB	Allocation Demand and Capability Data	M, N, Discovery
BC	Reliability Data	Discovery
BD	Allocation Energy and Supporting Data	M, N, Discovery
BE	Specific Assignment Data	M, N, Discovery
BF	Exclusive-Use Commitments of Major Power Supply Facilities	M, N, Discovery
BG	Revenue Data to Reflect Proposed Rates	M, N, Discovery
BH	Revenue Data to Reflect Present Rates	M, N, Discovery
BI	Fuel Cost Adjustment Factors	O, Discovery
BJ	Summary Data Tables	——
BK	Electric Utility Department Cost of Service, Total and as Allocated	L, M, N
BL	Rate Design Information	P

*Certain of the revised cost of service statements require data that have not been reported in all previous rate change proceedings. While the Commission proposes to request some information not obtained under the existing system, most of the "new data" in the proposed cost of service statements have been routinely requested during discovery.

III. Proposed Effective Date

The revised § 35.13 is proposed to be effective for any electric rate change application filed after 180 days from the date of issuance of the final rule. However, the Commission will encourage public utilities to file under the final revised rule during the 180 day period. The Commission is therefore proposing to waive the requirements of the existing § 35.13 for those utilities that request use of the revised cost-of-service format. This policy is a recognition that the ability of public utilities to retool for the filing requirements in the proposed § 35.13 may vary widely.

IV. Comment Procedure

Interested persons are invited to submit written data, views, comments or suggestions concerning the regulations proposed in this notice. The Commission requests that commenters specifically address certain issues presented in this preamble, namely the initial and continuing cost of compliance with the proposed rule in relation to the cost of the entire rate change application process as it now exists and the merits of the alternative definitions of "Period II" in terms of the use of calendar year data for test period purposes and the effect of each definition on the overall timing of rate change filings.

An original and 14 copies of any comment should be filed with the Secretary of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments must be received by April 14, 1980 and should refer to Docket

No. RM79–64. Written submissions will be available for public inspection at the Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. The Commission will consider all written comments submitted by the above date before acting on the proposed regulation.

(Federal Power Act, 16 U.S.C. §§ 792–828c; Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; Executive Order No. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter 1, Title 18 of the Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

Section 35.13 is revised to read as follows:

§ 35.13 Filing of changes in rate schedules.

(a) *General rule.* Every public utility shall file the information required by this section, as applicable, at the time it files with the Commission under § 35.1 a rate schedule, or part thereof, to supersede, supplement, or otherwise change the provisions of a rate schedule that is required to be filed with the Commission under § 35.1.

(1) *For any rate change not otherwise excepted.* Except as provided in subparagraphs (2) and (3), any public utility filing for a rate schedule change shall submit with its filing the information specified in paragraphs (b), (c), (d), (e), and (h) of this section, in accordance with paragraph (g) of this section.

(2) *For certain rate increases.* Any public utility filing for a rate schedule change that provides for a rate increase shall submit with its filing the information required in paragraph (a)(1) or the information required in paragraphs (b) and (c) of this section and in § 35.12(b)(2) and (5), in accordance with paragraph (g) of this section, if the proposed change is:

(i) an increase of less than $200,000 annually for the twelve months of Period I as defined in paragraph (d)(1)(ii);

(ii) a rate increase:

(A) To which all wholesale customers that belong to the affected rate class consent; and

(B) That is less than one million dollars annually for the twelve months of Period I as defined in paragraph (d)(1)(ii);

(iii) For a service of relatively short duration, and of a type for which the need and usage may not be reasonably forecastable, such as short-term power; or

(iv) An integral part of a coordination and interchange arrangement. This exception does not apply to interchange schedules providing for firm services, that is, schedules that include reserve assurance according to the criteria for general utility services established by the supplier.

(3) *For rate changes other than increases.* Any public utility filing for a rate schedule change that does not provide for a rate increase, or that results from a change in delivery points, a change in delivery voltage, or a similar change in service shall submit with its filing the information specified in paragraphs (b) and (c) of this section.

(4) *For parties concurring in coordination and interchange arrangements.* For coordination and interchange arrangements in the nature of power pooling transactions, all information required to be submitted in support of a rate schedule filing under paragraphs (a)(1) through (3) shall also be submitted by parties filing certificates of concurrence under § 35.1. If a representative is designated and authorized in accordance with § 35.1 to file supporting information on behalf of all parties, the representative may file the information for all parties under this paragraph in place of individual submittals by each party to a rate schedule.

(b) *General information.* Any public utility which files for a change in rate schedule under paragraph (a) shall

include with its filing the following general information:

(1) A list of documents submitted with the filing;

(2) The date or dates on which the filing utility proposes to make the changes effective;

(3) The names and addresses of persons to whom a copy of the proposed rate schedule has been mailed;

(4) A brief description of the proposed changes;

(5) A statement of the reasons for the proposed changes;

(6) A showing that all requisite agreement to the proposed rate schedule change, or to the filing of the rate schedule change, including any contract contained in any agreement, has in fact been obtained;

(7) A statement showing any expenses or costs included in cost of service statements for Period I or Period II which expenses or costs have been alleged or judged to be illegal, duplicative, or unnecessary labor costs demonstrably the product of discriminatory employment practices; and

(8) A form of notice suitable for publication in the **Federal Register** in accordance with § 35.8.

(c) *Information relating to the effect of the proposed changes.* Any public utility which files for a change in rate schedule under paragraph (a) shall also submit with its filing the following information or materials:

(1) A statement comparing sales and services and revenues from sales and services—

(i) By months and for the entire year, under both the rate schedule to be superseded or supplemented and the proposed changed rate schedule, each applied to the transactions for the twelve months immediately before and for the twelve months immediately after the proposed effective date of the new rate schedule, except as otherwise permitted under paragraph (c)(4); and

(ii) For each class of service, for each customer, and for each delivery point or points that constitute a billing unit, including billing quantities involved in the computation of the charges;

(2) A comparison of the proposed rate with other rates of the filing public utility for similar wholesale for resale and transmission services; and

(3) If any specifically assignable facilities have been or will be installed or modified in order to supply service under the proposed rate schedule, an appropriate available map or sketch and single line diagram showing the additions or changes to be made.

(4) If the utility files Statements BG and BH under paragraph (h), the utility may report the information required under paragraph (c)(1) for the twelve months of Period I instead of for the twelve months immediately before the proposed effective date of the rate change and, if applicable, for the twelve months of Period II instead of for the twelve months immediately after the proposed effective date of the rate change.

(d) *Cost of service information.* (1) *Definitions.* For purposes of submitting cost of service information—

(i) "Test period" means a finite time span during which a utility incurs costs and receives revenues, which costs and revenues are examined in the determination of a just and reasonable rate for a service rendered by the utility.

(ii) "Period I" means the most recent twelve consecutive months or the most recent calendar year for which actual data are available, the last day of the twelfth month of which is not more than fifteen months prior to the date of tender for filing of the proposed notice of change in rates and charges.

(iii) "Period II" means any period of twelve consecutive months after the end of Period I that begins:

(A) Not earlier than 12 months before the date on which the rate is proposed to become effective; and

(B) Not later than the date on which the rate is proposed to become effective.

(2) *Filing of Period I data.* (i) *Unadjusted data.* Any filing utility required to submit cost of service information under paragraph (a)(1), or which elects to file such information, shall submit Statements AA through BL described in subparagraph (h) using Period I unadjusted system cost data or

Period I adjusted system cost data under clause (ii).

(ii) *Adjusted data.* For any utility filing under paragraph (a)(1) for a rate increase that would have amounted to less than one million dollars during Period I, the filing of Period II system cost data under paragraph (d)(3) is optional. If a utility does not file Period II data—

(A) The utility may adjust Period I data to reflect changes that affect revenues and costs prior to the proposed effective date of the rate change and that are known and measurable with reasonable accuracy at the time of the filing, provided that:

(*1*) All Period I data are adjusted to reflect such changes; and

(*2*) The adjustments are fully supported in the appropriate cost of service statements;

(B) Period I will be the test period.

(3) *Filing of Period II data.* (i) *Statements.* (A) Any filing utility that is required to submit cost of service information under paragraph (a)(1) and that proposes a rate increase that would have amounted to one million dollars or more during Period I, shall submit Statements AA through BL described in paragraph (h) using estimated costs for Period II, except that a utility is not required to file Period II data if all wholesale customers that belong to the affected rate class have consented to the proposed rate increase.

(B) Any utility proposing a rate increase that would amount to less than one million dollars during Period I may submit Period II data under this subparagraph.

(C) *Test Period.* If Period II data are submitted under this subparagraph, Period II will be the test period.

(ii) *Work papers.* A filing utility shall submit work papers relating to Period II data statements whenever such statements are submitted under paragraph (d)(3)(i). Comprehensive explanation of the bases of the estimated figures shall be included. If the Period II estimated figures are derived from a regularly prepared corporate budget, the work papers shall include relevant excerpts from such budget. The work papers and additional explanatory material required to be provided in connection with a Period II submittal shall be organized and indexed according to both subject matter and witness, with index references to the specific statement supported by each segment of the material. Working papers shall also be cut or folded to letter size, and shall be assigned page numbers to assist in review and referencing.

(4) *Attestation.* A filing utility shall include an attestation by its chief accounting officer or other officer that the cost statements and supporting data submitted under paragraphs (d)(2) and (3) are true and accurate representations of the utility's books, budgets or other corporate documents, to the best of that officer's knowledge, information, and belief.

(5) *Additional informational requirements.* If the Commission orders an investigation of a proposed rate change filed under this section, the filing utility shall submit any information required under this subparagraph during the first month of each calendar quarter that begins after issuance of the order initiating the investigation and continuing until the Commission by final order concludes the investigation. The information required by this subparagraph is limited to material not previously submitted to the Commission.

(i) A filing utility shall inform the Commission of any actions involving significant changes in its financial condition, accounting methods, or operations, including the following:

(A) Issuance of securities;

(B) Significant increase or decrease in proposed construction program expenditures;

(C) Merger, consolidation or other major changes in the corporate organization; and

(D) Changes in the capital structures.

(ii) A filing utility shall submit to the Commission a copy of each order issued by any regulatory agency approving, rejecting or otherwise disposing of an application for an increase in the electric rates of the utility and a copy of each application for a rate increase

pending before a state regulatory agency.

(e) *Testimony and exhibits.* (1) *Burden of Proof.* Any utility filing for an increase in rates and charges shall be prepared to go forward at a hearing on reasonable notice on the data submitted, to sustain the burden of proof under the Federal Power Act, and to establish that proposed charges are just and reasonable and not unduly discriminatory or preferential or otherwise unlawful within the meaning of the Act.

(2) *Requirements to File.* If the rate schedule change is required to be filed under paragraphs (a) and (d), accompanied by Statements AA through BL, the filing utility shall submit testimony and exhibits with its rate increase filing. In order to avoid delay in processing rate filings, such testimony and exhibits shall be the case-in-chief of the utility in the event the matter is set for hearing. In addition to the material the utility chooses to submit as part of its case, the exhibits shall include the full cost of service data described in Statements AA through BL of paragraph (h), and the accompanying testimony shall include an explanation of these exhibits, including support for all adjustments to book or budgeted data relied on in preparing such exhibits.

(3) *Reference to filed information.* To the extent that testimony and exhibits required to be filed pursuant to paragraph (e)(2) duplicate information required to be submitted in Statement AA through BL described in paragraph (h), the testimony and exhibits may include relevant material by reference to the specific statement which contains such material.

(f) *Cost of service data required by letter.* A filing public utility may be required by letter of the Secretary, to submit specified cost data, if such data may be needed for Commission analysis, even if a rate schedule required to be on file with this Commission is not required to be supported by cost of service data as set forth in this section.

(g) *Commission precedents and policy.* When submitting the supporting cost of service data required under paragraph (d), a filing utility shall conform all filings to any cost of service requirements that are generally applicable to all utilities, including the provisions of this part and any order of this Commission applicable to such utility.

(h) *Cost of service statements.* The following Statements AA through BL shall be submitted by the filing utility as required by paragraph (d) and in accordance with this paragraph:

Statement

AA—Balance sheets
AB—Income statements
AC—Retained earnings statement
AD—Cost of plant
AE—Accumulated depreciation and amortization
AF—Specified deferred credits and operating reserves
AG—Specified plant accounts (other than plant in service) and deferred debits
AH—Operation and maintenance expenses
AI—Wages and salaries
AJ—Depreciation and amortization
AK—Taxes other than income taxes
AL—Working capital
AM—Construction work in progress
AN—Notes payable
AO—Allowance for funds used during construction
AP—Federal income tax deductions—interest
AQ—Federal income tax deductions—other than interest
AR—Federal tax adjustments
AS—Additional state income tax deductions
AT—State tax adjustments
AU—Revenue credits
AV—Rate of return
AW—Cost of short-term debt
AX—Other recent and pending rate changes
AY—Income and revenue tax rate data
BA—Wholesale customer rate groups
BB—Wholesale customer rate groups
BC—Reliability data
BD—Allocation energy and supporting data
BE—Specific assignment data
BF—Exclusive-use commitments of major power supply facilities
BG—Revenue data to reflect proposed rates
BH—Revenue data to reflect present rates
BI—Fuel cost adjustment factors
BJ—Summary data tables
BK—Electric utility department cost of service, total and as allocated
BL—Rate design information

(1) *Statement AA—Balance sheets.* Statement AA consists of balance sheets as of the beginning and the end of Period I and Period II, and the most recently available balance sheet, including any applicable notes, and an explanation of any significant accounting changes since the most recent filing by the utility under this section that involves the same wholesale customer rate class. Balance sheets should be constructed in accordance with the annual report form for electric utilities specified in Part 141.

(2) *Statement AB--Income statements.* Statement AB consists of income statements for Period I and Period II, and the most recently available income statement, including any applicable notes, and an explanation of any significant accounting changes since the most recent filing by the utility under this section that involves the same wholesale customer rate class. Income statements shall be prepared in accordance with the annual report form for electric utilities specified in Part 141.

(3) *Statement AC—Retained earnings statement.* Statement AC consists of retained earnings statement for Period I and Period II, and the most recently available retained earnings statement, including any notes applicable thereto. Retained earnings statements shall be prepared in accordance with the annual report form for electric utilities specified in Part 141.

(4) *Statement AD—Cost of plant.* Statement AD is a statement of the original cost of total electric plant in service according to functional classification for Period I and Period II. If the plant functions and subfunctions of Period I and Period II are different, the differences shall be explained and justified.

(i) For each separately identified function and subfunction of production plant or transmission plant, the original cost shall be stated as of the beginning of the first of the month and the end of each month of Period I and Period II, with an average of the thirteen balances for each period. If any of the Period I or Period II thirteen monthly balances is not available or not representative of normal planning of the utility for plant in service, the statement shall include an explanation of the relevant circumstances.

(ii) For each separately identified function and subfunction of plant other than production or transmission, the original cost shall be stated as of the beginning and the end of both Period I and Period II, with an average of the beginning and end balances for each period. If any of the Period I or Period II balances is not available or not representative of normal planning of the utility for plant in service, the statement shall include an explanation of the relevant circumstances.

(iii) Electric plant in service shall be shown in accordance with each of the following five major functional classifications:

(A) Production;
(B) Transmission;
(C) Distribution;
(D) General and Intangible; and
(E) Common and Other.

(iv) To the extent feasible, completed construction not classified in accordance with paragraph(h)(4)(iii) of this section shall be shown in accordance with tentative classification to major functional accounts. If this is not feasible, such facilities shall be included as other plant under paragraph (h)(4)(iii)(E) of this section.

(v) To the extent necessary to support the proposed rate, a utility shall supply the original cost information for the five major functional plant classifications in paragraph(h)(4)(iii) of this section divided into subfunctional categories. Where subfunctional original cost information is provided, the filing utility shall explain the importance of providing such information to support the proposed rate. Each category shall be described in substantive terms, such as steam electirc production or high voltage transmission.

(vi) Subfuncitional categories shall be selected as appropriate under the following criteria:

(A) Plant categories shall be established as necessary to segregate

costs for production services with special characteristics, such as base, intermediate or peaking load production services. Statement AD shall include a description of each such service and shall list a brief descriptive title for each corresponding subfunctional category.

(B) Transmission plant categories shall be chosen to reflect the extent to which the facilities are proposed to be allocated on a common basis among all or specific segments of utility services. For descriptive purposes, plant may also be categorized according to accounting or engineering terminology, such as hight voltage overhead lines. Statement AD shall include brief descriptive transmission category titles and explain the basis for the titles. If all transmission plant will be allocated among utility services on the basis of a single set of allocation data, original cost shall be shown in total without subfunctionalization.

(C) Distribution plant categories shall be selected according to engineering or use characteristics meaningful in terms of allocations or assignments to wholesale services such as substations, overhead lines, meters, or non-wholesale. Statement AD shall include a brief descriptive distribution category titles and shall explain the basis for the titles.

(D) A filing utility is not required to divide general, intangible, common, and other categories into subfunctional categories if the functions of plant are stated as being related to utility labor expense. If the utility divides the categories of plant into subfunctional categories, the subfunctional categories shall be chosen to group together facilities that are generally equivalent in sharing a significant correlation to selected plant or expense items for which an allocation to wholesale services is independently determimable. Statement AD shall include a brief descriptive title for each general and intangible category, and for each common and other category, with an explanation of the basis of each category selection.

(E) A separate category shall be provided for each specific assignment of plant reported in Statement BE. Such assignments are applicable principally but not necessarily exclusively to distribution facilities. Statement AD shall include brief descriptive titles consistent with Statement BE.

(F) A separate category shall be provided for each exclusive-use commitment of major power supply facilities as required to be reported at Statement BF. Statement AD shall include brief descriptive titles consistent with Statement BF.

(5) *Statement AE—Accumulated depreciation and amortization.* Statement AE is a statement of the accumulated provision for depreciation and amortization of electric plant according to functional classification for Period I and Period II.

(i) For each function and subfunction of electric production or transmission plant in service identified in statement AD, the filing utility shall set forth the accumulated depreciation and amortization as of the beginning of the first month and the end of each month of Period I and Period II. The utility shall state an average for each period computed and stated as the average of the thirteen balances. If any of the Period I or Period II thirteen monthly balances is not available or not representative of historical planning of the utility for depreciation reserves, the statement shall include an explanation of the relevant circumstances.

(ii) For each function and subfunction of electric plant in service other than production or transmission, identified in Statement AD, the filing utility shall state the accumulated depreciation and amortization as of the beginning and the end of Period I and Period II, with an average of the beginning and end balances for each period. If any of the Period I or Period II balances is not available or not representative of the historical planning of the utility for depreciation reserves, the statement shall include an explanation of the relevant circumstances.

(iii) Accumulated depreciation and amortization shall be shown by the major functional classifications selected by the filing utility in Statement AD under paragraph (h)(4), as follows:

(A) Production;

(B) Transmission;

(C) Distribution;

(D) General and Intangible; and

(E) Common and Other.

(iv) The major functional classifications of accumulated depreciation and amortization data shown in clause (iii) shall be divided into the subfunctional categories selected by the utility in Statement AD under paragraph (h)(4), to the extent such data are available.

(v) If accumulated depreciation and amortization data are not available for any subfunction selected in Statement AD, Statement AE shall:

(A) provide a comparison of the current depreciation rate of the major functional classification and the depreciation rate estimated to be appropriate to the subfunctional category; and

(B) state and explain the estimation techniques which the utility proposes to utilize in the absence of subfunctional data, such as the proration of accumulated depreciation and amortization data among the subfunctional categories according to the data for electric plant in service in Statement AD. If any of the proposed estimation techniques require data that is not provided elsewhere in the cost of service statements in paragraph (h) of this section, the filing utility shall supply the necessary data in Statement AE.

(6) *Statement AF—Specified deferred credits and operating reserves.* Statement AF is a statement of balances of specified accounts and items which are to be considered in the determination of the net original cost rate base. All required balances are to be stated as of the beginning and end of both Period I and Period II, with an average of the beginning and end balances for each period. If any of the Period I and Period II balances are not available or not representative of the historical experience of the utility, the statement shall include an explanation of the relevant circumstances. If subaccounts are maintained to reflect differences in ratemaking treatment among regulatory authorities that have jurisdiction, balances shall be provided in accordance with such subaccounts, with detailed explanations of the bases upon which the subaccounts were established and are maintained. The balances of deferred credits and operating reserves required to be filed in the statement are described in paragraph (h)(6) (i) through (x) of this section. All references to numbered accounts refers to the Commission's Uniform System of Accounts, 18 C.F.R. Part 101.

(i) For each resale customer group whose rates are at issue, balances shall be stated for customer advances for construction Account 252, with details of circumstances under which the advances were made and are to be refunded. Total electric balances shall be stated to include those for the resale customer groups.

(ii) Total electric balances shall be stated for accumulated deferred investment tax credits Account 255. If the filing utility maintains records to show Account 255 component balances according to the major functional classification identified in Statement AD under paragraph (h)(4), the statement shall provide the component balances by function. If the data are not available by function, the filing utility shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statement in this paragraph, the filing utility shall supply the necessary data, such as historical functional patterns of plant additions eligible for the tax credits, in Statement AF. The filing utility shall state whether the Internal Revenue Code general rule

is applicable with respect to restrictions on credit treatment for ratemaking purposes. If the general rule is not applicable, the filing utility shall state which election it has made with respect to special rules for ratable or immediate flow-through for ratemaking purposes.

(iii) Total electric component balances shall be stated for accumulated deferred income tax Account 281 pertaining to accelerated amortization property. Separate components shall be shown for defense facilities, pollution control and fuel conversion facilities, and other facilities. Balances shall be shown for each component and totaled for the electric utility department. If the filing utility maintains records to show Account 281 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the statement shall provide such component balances. If data are not available by function, the filing utility shall describe the procedure that it believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall supply the necessary data in Statement AF.

(iv) Total electric component balances shall be stated for accumulated deferred income tax Account 282 pertaining to electric utility property other than accelerated amortization property. The balances in Account 282 shall be itemized in detail sufficient to identify the specific properties involved and shall be listed according to the accounting entries, such as liberalized depreciation, for which interperiod tax allocation was used and included in this account. Component balances shall be itemized and totaled for the electric utility department. If the filing utility maintains records to show Account 282 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the statement shall provide such component balances by function. If the data are not available by function, the filing utility shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall supply the necessary data, such as historical functional patterns of plant additions, in Statement AF.

(v) Total electric component balances shall be stated for accumulated deferred income tax Account 283 pertaining to interperiod income tax allocations not related to property. The component balances in Account 283 shall be itemized in detail and listed according to the accounting entries for which interperiod tax allocation was used. Component balances shall be shown individually and in total for the electric utility department. If the filing utility maintains records to show Account 283 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the statement shall provide such component balances by function. If the data are not available by function, the filing utility shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall supply the necessary data in Statement AF.

(vi) The total electric component balances shall be stated for property insurance reserve Account 261. If the utility maintains records to show Account 261 component balances

according to the major functional classifications identified in Statement AD under paragraph (h)(4), the statement shall provide such component balances by function. If the data are not available by function, the filing utility shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall supply the necessary data in Statement AF.

(vii) Electric utility balances shall be stated for damages reserve Account 262.

(viii) Electric utility balances shall be shown for pensions and benefits reserve Account 263.

(ix) Electric utility component balances shall be shown for miscellaneous operating reserves Account 265. Balances shall be itemized in detail sufficient to indicate the nature of each reserve requirement. Component balances shall be shown individually and in total for Account 265.

(x) Electric utility balances shall be shown for every other item that the applicant believes should be included in Statement AF. The statement shall explain the reasons for inclusion of each item.

(7) *Statement AG—Specified plant accounts (other than plant in service) and deferred debits.* Statement AG is a statement of balances of specified accounts and items that are to be considered in the determination of the net original cost rate base. All required balances are to be stated as of the beginning and the end of Period I and Period II, with an average of the beginning and end balances for each period. If any of the Period I or Period II balances is not available or not representative of the historical experience of the utility, the statement shall include a full explanation of the relevant circumstances. If subaccounts are maintained to reflect differences in ratemaking treatment among regulatory authorities having jurisdiction, balances shall be provided in accordance with such subaccounts, with detailed explanations of the bases upon which the subaccounts were established and maintained. The balances required to be submitted under Statement AG are described in paragraph (h)(7)(i) through (vii) of this section.

(i) For each separately identified major functional classification selected by the utility in Statement AD, the electric utility land and land rights balances shall be stated for electric plant held for future use (Account 105). If itemized in detail, balances should be totaled for each major functional classification.

(ii) Electric utility component balances shall be stated for each item of construction work in progress (Account 107) for pollution control or fuel conversion facilities that qualify for inclusion in rate base. Component balances shall be shown individually and in total.

(iii) For each major functional classification under Statement AD and with respect to property otherwise includable in rate base, the balances shall be stated for extraordinary property losses Account 182. If itemized in detail, balances shall be totaled for each major functional classification. The filing utility shall provide information about Commission authorization for any loss included in Account 182 and shall state when the loss was claimed for tax purposes.

(iv) For each major functional classification under Statement AD, the component balances shall be stated for research, development and demonstration (RD&D) expenditures Account 188. The data shall include both the monthly amounts charged to Account 188 and the monthly amounts transferred to each expense account for each RD&D project.

(v) Total electric component balances shall be stated for accumulated deferred income taxes Account 190. Components of balances in Account 190 shall be itemized in detail sufficient to show the nature of the specific transactions which give rise to interperiod tax allocation.

balances shall be itemized and totaled for the electric utility department. If the utility maintains records to show Account 190 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the statement shall provide such component balances by function. If the data are not available by function, the filing utility shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall supply the necessary data, such as historical functional patterns of plant additions, in Statement AG.

(vi) Balances shall be shown for every other item that the applicant believes should be included in Statement AG. The statement shall provide support for inclusion of each item, and a brief descriptive title for each such item.

(8) *Statement AH — Operation and maintenance expenses.* Statement AH is a statement of electric utility operation and maintenance expenses for Period I and Period II.

(i) For Period I and Period II, operation and maintenance expenses shall be reported in separate accounts according to the form prescribed by the Commission's Uniform System of Accounts, 18 C.F.R. Part 101. The statement shall include by function additional operation and maintenance expenses attributable to the common and other plant classification identified in Statement AD under paragraph (h)(4). The filing utility shall apply the following principles in developing Period I and Period II data for this statement:

(A) Total production operation and maintenance expenses shall be segregted into energy, demand, and other components. The applicant shall specifically state and support its criteria for classifications between energy and demand, and for use of the production "other" classification, such as specific assignments related to sales from particular generating units.

(B) Fuel expense for cost of service purposes shall be total as-burned expense incurred. If the applicant defers a porton of such expense for accounting purposes, the deferral amount shall be separately stated and accompanied by material that shows computational detail in support of such ammount. If a claimed nuclear fuel expense reflects a change in the estimated net salvage value of nuclear fuel, the amounts involved shall be shown and relevant circumstances explained.

(C) If the amount of a production fuel expense is affected by abnormal Period I water availability for hydroelectric generation, the amount shall be shown as an individual item of production energy related expense. Supporting detail is required.

(ii) For Period I and Period II, the utility shall itemize and subtotal all operation and maintenance expenses according to the major functional classification of Statement AD in paragraph (h)(4) and the subfunctional categories of those classifications. The operation and maintenance expenses itemized under the production classification and each of its subfunctional categories shall be further divided to reflect expenses relating to the energy component (list each item by account number and compute fuel costs on an asburned basis), the demand component, and any other production expenses.

(iii) For Period I and Period II, the utility shall itemize and subtotal all operation and maintenance expenses incurred under the categories of customer accounting, sales and customer service and information.

(iv) For Period I and Period II, the utility shall itemize administrative and general expenses by groups that are directly assignable, such as regulatory Commission expenses, or that are related to selected plant or expense items for which an allocation to wholesale services is indepedently

determinable, such as items related to labor expense or to a category of production plant in service. Administrative and general expenses shall include a detailed itemization of the general advertising Account 930.1 and the miscellaneous general expenses Account 930.2. Where applicable, separate items shall be shown for general plant maintenance, and for common and other plant maintenance.

(v) In addition to annual data for each of the two periods, monthly expense data by accounts is required for fuel (Accounts 501, 518, and 547) and purchased power (Account 555). Monthly purchased power data shall be subtotaled for each type of transaction, such as firm power or economy interchange power. List the other party to each type of transaction. For monthly fuel Accounts 501, 518, and 547 and for each type of purchased power transaction, the monthly data shall identify components to be claimed under the fuel adjustment clause of the filing utility.

(9) *Statement AI—Wages and Salaries.* Statement AI consists of statements of the electric utility wages and salaries, for Period I and Period II, that are included in operation and maintenance expenses reported in Statement AH.

(i) For Period I and Period II, the distribution of wages and salaries shall be shown by function according to the form prescribed for operation and maintenance expenses by the Commission's Uniform System of Accounts (18 CFR Part 101). The statement shall also include by function additional wages and salaries attributable to common and other plant classification identified in Statement AD in paragraph (h)(4).

(ii) For Period I and Period II, total production wages and salaries shall be itemized and subtotaled into energy and demand related components in accordance with classifications of Statement AH operation and maintenance production expenses of which production wages and salaries are a part.

(10) *Statement AJ—Depreciation and amortization expenses.* Statement AJ shall consist of statements of depreciation and amortization expenses for Period I and Period II.

(i) For Period I and Period II, the depreciation and amortization expenses and the depreciable plant balances of the filing utility shall be shown in accordance with major functional classifications selected by the utility in Statement AD under paragraph (h)(4), as follows:

(A) Production;
(B) Transmission;
(C) Distribution;
(D) General and intangible; and
(E) Common and other.

(ii) The major functional classifications of depreciation and amortizaiton expenses shown in paragraph (h)(10) (i) of this section shall be divided into the subfunctional categories selected for electric plant in service in Statement AD, to the extent such data are available.

(iii) If depreciation and amortization expense data are not available for any subfunctional category selected in Statement AD, Statement AJ shall:

(A) provide a comparison of the current depreciation rate of the major functional classification and the depreciation rate estimated to be appropriate to the subfunctional category; and

(B) state, and explain the estimation techniques that the utility utilized in developing each estimated subfunctional depreciation rate. If utilization of such estimation techniques requires data that is not provided elsewhere in the cost of service statements in this paragraph, such data shall be supplied in Statement AJ.

(iv) For Period I and Period II, the statement shall show the annual depreciation rate applicable to each function and subfunction for which depreciation expense is reported. The statement shall indicate the basis upon which the depreciaiton rates were established. If Period I or Period II data reflect changes in depreciaiton rates, detailed studies in support of such changes shall be included in or appended to Statement AJ.

(11) *Statement AK—Taxes other than income taxes.* Statement AK consists of

statements of taxes other than income taxes for Period I and Period II.

(i) For Period I and Period II, the utility shall itemize and total any taxes other than income taxes according to paragraph (h)(11)(i) (A) through (D) of this section.

(A) *Revenue taxes.* Statement AK shall show total revenue taxes levied by each taxing authority and identify the revenue taxes, under present rates and under proposed rates, applicable to wholesale services for which a change is proposed. Identify revenue taxes associated with each revenue credit item reported in Statement AU under paragraph (h)(21).

(B) *Real estate and property taxes.* The filing utility shall itemize and total all real estate and property taxes. If the filing utility maintains records to show tax component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the statement shall supply the component balances by function. If the data are not available by function, the filing utility shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraphs, the filing utility shall supply the necessary data in Statement AK.

(C) *Payroll taxes.* The filing utility shall itemize and total all payroll taxes. If the filing utility maintains records to show tax component balances according to the major functional classifications identified in Statement AD in paragraph (h)(4), the statement shall provide the component balances by function. If the data are not available by function, the filing utility shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rates. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall provide the necessary data in Statement AK.

(D) *Miscellaneous taxes.* The utility shall itemize and total all miscellaneous taxes which are directly assignable or which are related to any selected plant or expense item for which an allocation to wholesale services is independently determinable, such as items related to transmission plant in service or to net distribution plant.

(ii) If any of the taxes itemized under paragraph (h)(11)(i) of this section are levied by a taxing authority that is a customer, or is related to a customer, whose services would be affected by the proposed rate schedule change, the utility shall show amounts of such taxes according to taxing authority, identify the related customer, and provide an explanation of the relevant circumstances.

(12) *Statement AL—Working capital.* Statement AL consists of statements for Period I and Period II designed to establish the need for working capital to maintain adequate levels of operating supplies, to meet required prepayments, and to meet ongoing cash disbursements that must be made at a time different than related revenue receipts for utility services rendered.

(i) The utility shall supply statements to show monthly balances of operating supplies and prepayments itemized under paragraph (h)(12)(i) (A) through (C) of this section. All required balances shall be stated as of the beginning of the first month and the end of each month of Period I and Period II, with an average of the thirteen balances for each period. If any of the Period I or Period II balances is not available or not representative of normal utility operations, the statement shall include an explanation of the relevant circumstances. Operating supply and prepayment balances shall be itemized under the following categories:

(A) *Fuel supplies.* Statement AL shall indicate the fuel supply balances for each type of electric utility production plant, except hydraulic. The filing utility

shall describe its overall fossil fuel supply objectives for Period I and Period II, in terms of projected average days of burn for major fossil fuel generating stations, if feasible. The filing utility shall explain substantial differences, if any, between actual Period I inventories and the target objectives, or between Period II objectives and Period I objectives. Nuclear fuel balances shall include fuel in stock, fuel in the reactor and spent fuel in the process of cooling (Accounts 120.2, 120.3, 120.4), less accumulated provision for amortization of nuclear fuel assembles (Account 120.5).

(B) *Plant materials and operating supplies.* Statement AL shall indicate material and operating supply balances for each of the major electric utility operating functions of production, transmission, and distribution, and for each significant type of miscellaneous operating supplies. Miscellaneous supplies shall be grouped to facilitate suitable allocations or assignments among utility services.

(C) *Prepayments.* Statement AL shall indicate prepayment balances for each major prepayment item, together with a brief description of the item. Balances shall be grouped and subtotaled to facilitate suitable allocations or assignments among utility services.

(ii) Statement AL shall indicate average monthly working cash requirements that reflect the extent to which utility service revenues are received later or earlier than cash disbursements necessary to provide the services. The working cash requirements shall be computed in accordance with § 35.24 of this chapter.

(13) *Statement AM—Construction work in progress.* Statement AM is a statement of the amounts of construction work in progress described according to functional classification for Period I and Period II. For production plant and transmission plant, the utility shall state the balances as of the beginning of the first month and the end of each month of Period I and Period II, with an average of the thirteen balances for each period. For each function of plant identified in Statement AD other than production or transmission, the utility shall state the balances as of the beginning and the end of Period I and Period II, with an average of the beginning and end balances for each period. If any Period I or Period II balance is not available, the statement shall include an explanation of the relevant circumstances. Pollution control or fuel conversion facility amounts reported in Statement AG should be excluded from amounts reported in this statement.

(14) *Statement AN—Notes payable.* Statement AN is a statement of the electric utility portion of average notes payable for Period I and Period II. The utility shall indicate balances as of the beginning of the first month and the end of each month of Period I and Period II, and an average of the thirteen balances for each period. If any of the Period I or Period II balances is not available or not representative of normal operations, the statement shall include an explanation of the relevant circumstances. If applicable, the statement shall also show the allocations between electric and other utility departments on a basis that includes consideration of construction work in progress.

(15) *Statement AO—Allowance for funds used during construction.* Statement AO is a statement of the basis of the rate for computing the allowance for funds used during construction for Period I and Period II.

(i) The filing utility shall show the computations of the maximum rates for the construction allowances computed in accordance with plant instructions of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The rates shown shall be those required to be computed annually, and shall be provided for each annual period that includes any part of Period I or Period II. If the filing utility proposes to use a net of tax rate, the utility shall show the derivation for both the gross and net rates.

(ii) If the book allowance amounts do not reflect the maximum rates for allowances for funds computed in accordance with paragraph (h)(15)(i), of

this section the utility shall show the derivation for the actual rates utilized in computing allowances for funds used during construction, including derivation of any net of tax rate utilized by the filing utility.

(16) *Statement AP—Federal income tax deductions—interest.* Statement AP is a statement of electric utility interest charges for Period I and Period II. For each period, the total electric utility interest shall be stated in terms of three or more component items described in paragraph (h)(16)(i) through (iv) of this section.

(i) The Account 432 allowance for borrowed funds used for electric utility construction shall be stated as a separate component item of interest. Supporting detail shall be shown, including computation of the amounts on the basis of AFUDC rates claimed at Statement AO.

(ii) The statement shall include a separate component item consisting of Account 431 interest for borrowed funds used for electric utility construction. If applicable, the statement shall also show all elements of Account 431 related to purposes other than electric utility construction, with detailed supporting material, such as a computation of allocations between electric and other utility departments with explanatory material to support the basis of such allocations.

(iii) The interest on long-term debt required for rate base investment shall be stated as a separate component. The interest amount shall be consistent with that shown and utilized in Statement BK under paragraph (h)(36).

(iv) The statement shall show other interest items appropriate in the determination of net taxable income allocable to the wholesale services at issue. Each such item shall be described and supported, and accompanied by a statement of the basis on which the item is allocable to the wholesale services. Statement AP shall also list a short descriptive title for each item.

(17) *Statement AQ—Federal income tax deductions—other than interest.* Statement AQ is a statement of other deductions from net operating income before Federal income taxes, for Period I and Period II, which deductions are appropriate in determining the net taxable income allocable to the wholesale services subject to the proposed rate change. Unallowable deductions shall be included as negative entries in this statement. Deductions shall be itemized in accordance with paragraph (h)(17) (i) through (iii) of this section and individually identified by a brief descriptive title.

(i) The differences between tax and book depreciation may be stated as a separate component item in total, or as several individual items. Sufficient detail shall be provided to identify the effects of each constituent element of the total difference between tax and book depreciation.

(ii) Taxes and pensions capitalized shall be stated as a separate component item.

(iii) Other deduction items appropriate in the determination of net taxable income allocable to the wholesale services at issue. Each such item shall be described and supported.

(18) *Statement AR—Federal tax adjustments.* Statement AR is a statement of adjustments to Federal income taxes for Period I and Period II. If subaccounts are maintained to reflect differences in ratemaking treatment among regulatory authorities having jurisdiction, adjustment amounts shall be provided in accordance with such subaccounts. The statement shall contain detailed explanations of the bases upon which the subaccounts were established and are maintained.

(i) For each major function of plant identified in Statement AD under paragraph (h)(4), the electric utility component adjustment shall be stated for the Federal portions of the provision for deferred income tax Account 410.1. If the data are not available by function, the filing utility shall state the amounts for total electric utility and shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of

allocation to electric service under the proposed rate. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall supply the necessary data in Statement AR. The utility shall provide the adjustment amounts for total electric, and to the extent available each such major functional component, accompanied by summary totals segregated in accordance with related balance sheet Accounts 281, 282, 283, and 190 [*see* Statements AF and AG]. Account 190 items require a negative sign for entries in Statement AR. The summarized items shall be identified by the account number.

(ii) The data required by paragraph (h)(18)(i) for Account 410.1 shall also be provided for the Federal portions of the provision for deferred income tax-credit Account 411.1.

(iii) For each major functional classification of plant identified in Statement AD under paragraph (h)(4), the electric utility component shall be provided for investment tax credits generated for Period I and Period II, credits utilized for each period, and the allocations to current income for each period. If the data are not available by function, the filing utility shall state the amounts for total electric utility and shall describe the procedure that the utility believes will reasonably apportion the total electric balances on an estimated basis among the major functional classifications for the purpose of allocation to electric service under the proposed rule. If such estimated apportionment procedure requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing utility shall supply the necessary data in Statement AR. If itemized in detail, balances shall be subtotaled for each major function, and totaled for the electric utility department. Detailed data must be consistent with that provided in Statement AF under paragraph (h)(6).

(iv) Additional Federal income tax adjustments shall be listed and designated as other adjustment items, and a brief descriptive title shall be provided for each item. The statement shall explain the reasons for inclusion of each item, and shall indicate the basis on which each will be assigned or allocated to the wholesale services subject to the proposed rate change and to the other electrical utility services.

(19) *Statement AS—Additional State income tax deductions.* Statement AS is a listing of State income tax deductions for Period I and Period II, in addition to those listed at Statements AP and AQ for Federal tax purposes. The statement shall explain the reasons for inclusion of each item. The statement shall indicate the basis on which each item is to be assigned or allocated to the wholesale services at issue and to the other electric utility services. If applicable, unallowable deductions shall be included as negative entries in this statement. The statement shall provide the percentage of Federal income tax payable which may be deductible for State income tax purposes, if applicable. [*See* also Statement AY, dealing with tax rate data.]

(20) *Statement AT—State tax adjustments.* Statement AT is a statement of adjustments to State income taxes for Period I and Period II. The data in Statement AT shall be prepared and presented as prescribed for Federal tax adjustments in Statement AR. Statement AT data shall be annotated as necessary to identify State tax adjustments that are not properly deductible for Federal tax purposes.

(21) *Statement AU—Revenue credits.* Statement AU is for Period I and Period II, a statement of other operating revenue accounts (Accounts 450 through 456), and other revenue items, such as short-term firm sales in Account 447, that are appropriately credited to the cost of service for determinations of costs allocable to the wholesale services subject to the proposed rate change. Statement AU shall include revenue credits proposed for exclusive-use commitment of major power supply facilities according to instructions for

preparation of Statement BF under paragraph (h)(31). When applicable, revenue taxes shall be stated for each revenue credit item. The statement shall explain the reasons for inclusion of each item, and shall indicate the basis for assigning or allocating each item to the wholesale services subject to the proposed rate change and to the other electric utility services.

(22) *Statement AV—Rate of return.* Statement AV is a statement and explanation of the percentage rate of return requested by the utility. This statement shall include the complete capital structure, including ratios, component costs and weighted component costs claimed by the filing utility. The filing utility shall submit additional data where any component of the capital of the filing utility is not primarily obtained through its own financing, but is primarily obtained from a company by which the filing utility is controlled, as defined in the Commission's Uniform System of Accounts. The additional data, if required, shall be submitted with respect to the debt capital, preferred stock capital and common stock capital of such controlling company or any intermediate company through which such funds have been secured. The utility shall provide a copy of the latest prospectus issued by the controlling company, any superimposed holding company or subsidiary companies. A filing utility shall update the data in Statement AV as required in § 35.13(d)(5).

(i) *General.* This statement shall show, based on the capitalization of the utility, the cost of debt capital and preferred stock capital, the return on the common equity of the filing utility and the resulting overall rate of return requested.

(A) For Period I and, if applicable, Period II, the applicant shall show in tabular form the following:

(1) Cost of each capital element, including claimed return on equity capital;

(2) Capitalization amounts and ratios;

(3) Weighted cost of each capital element; and

(4) Overall claimed rate of return.

(B) When a Period II filing is submitted, the filing company will provide:

(1) A full explanation of, and supporting worksheets for, the *pro forma* adjustments to the actual capitalization data to arrive at the Period II capitalization; and

(2) The *pro forma* adjustment to Period I data to arrive at the Period II amount for unappropriated undistributed subsidiary earnings (Account 216.1).

(C) If not included elsewhere in the filing, the amount for Account 216.1 for Period I is to be submitted as part of this statement.

(ii) *Debt capital.* (A) This statement shall show the weighted cost for all issues of long-term debt capital as of the end of Period I and, if applicable, Period II. The weighted cost is calculated by: *(1)* multiplying the cost of money for each issue under paragraph (h)(22)(ii)(B)*(6)* of this section by the principal amount outstanding for each issue, which yields the annualized cost for each issue; and *(2)* adding the annual cost of each issue to obtain the total for all issues, which is divided by the total principal amount outstanding for all issues to obtain the weighted cost for all issues.

(B) This statement shall show the following for each class and series of long-term debt outstanding as of the end of Period I and estimated to be outstanding as of the end of Period II, if applicable:

(1) Title;

(2) Date of offering and date of maturity;

(3) Interest rate;

(4) Principal amount of issue;

(5) Net proceeds to the filing utility;

(6) Cost of money, which is the yield to maturity at issuance based on the interest rate and net proceeds to the company determined by reference to any generally accepted table of bond yields;

(7) Principal amount outstanding;

(8) Name and relationship of issuer and if the debt issue was issued by an affiliate; and

(9) If the filing utility has acquired at a discount or premium, some part of the outstanding debt which could be used in meeting sinking fund requirements, or for some other reason, it shall show the annual amortization of the discount or premium for each issue of debt from the date of the reacquisition over the remaining life of the debt being retired. The filing utility shall separately show the total discount and premium to be amortized, and the amortized amount applicable to Period I and, if applicable, Period II.

(C) The statement shall show the interest coverage before and after taxes, for the twelve months of Period I experience based on the indenture requirements. The statement shall provide a copy of the indenture references used in the calculation and a copy of the worksheets used to make the calculations, together with explanations appropriate to understand the calculations.

(iii) *Preferred stock and preference stock capital.*

(A) This statement shall show the weighted cost for all issues of preferred and preference stock capital as of the end of Period I and, if applicable, Period II. The weighted cost is calculated by: *(1)* multiplying the cost of money for each issue under paragraph (h)(22)(iii)(B)*(9)* of this section by the par amount outstanding for each issue, which yields the annualized cost for each issue; and *(2)* adding the annual cost of each issue to obtain the total for all issues, which is divided by the total par amount outstanding for all issues to obtain the weighted cost for all issues.

(B) The statement shall show for each class and issue of preferred and preference stock outstanding as of the end of Period I and estimated to be outstanding as of the end of Period II, if applicable:

(*1*) Title;
(*2*) Date of offering;
(*3*) If callable, call price;
(*4*) If convertible, terms of conversion;
(*5*) Dividend rate;
(*6*) Par of stated amount of issue;
(*7*) Net proceeds to the filing utility;
(*8*) Ratio of net proceeds to gross proceeds received by the filing utility;
(*9*) Cost of money (dividend rate divided by the ratio of net proceeds to gross proceeds for each issue);
(*10*) Par or stated amount outstanding;
(*11*) If issue is owed by an affilitate, state name and relationship of owner.

(iv) *Common stock capital.* This statement shall show the following information for each sale of common stock during the five-year period preceding the date of the balance sheet for the end of Period I and for each sale of common stock between the end of Period I and the date that the proposed rate is filed:

(A) Number of shares offered;
(B) Date of offering;
(C) Gross proceeds at offering price;
(D) Underwriter's commission;
(E) Dividends per share;
(F) Net proceeds to company;
(G) Issuance expenses; and
(H) Whether issue was offered to stockholders through subscription rights or to the public and whether common stock was issued for property or for capital stock of others.

(v) *Supplementary financial data.* The utility shall submit a statement indicating the sources and uses of funds for Period I and as estimated for Period II and a copy of the filing utility's most recent annual report to the stockholders and the filing utility's prospectus for its most recent issue of securities.

(23) *Statement AW—Cost of short-term debt.* In Statement AW, the utility shall provide a statement of the short-term debt cost rate of the filing utility as of the end of Period I and as estimated for the end of Period II, together with details supporting each of these two stated cost rates. The short-term debt cost shown in Statement AW should include only the cost that appears on the income statement as interest expense and should not include nominal forms of financing, such as trust agreements.

(24) *Statement AX—Other recent and pending rate changes.* Statement AX is a statement describing the extent to which operating revenues are subject to refund for Period I and, if applicable, Period II, for each rate change filed with the Federal, state, or other regulatory body that has jurisdication. The utility shall

list and submit a copy of any orders in which applications for a rate increase have been acted on by state regulatory bodies during Period I, Period II, or the interval between Period I and Period II, and a copy of pending applications that have not been acted on. Statement AX shall reflect information available at the time of submittal under this paragraph. A filing utility shall thereafter update the data in Statement AX as required in § 35.13(d)(5).

(25) *Statement AY—Income and revenue tax rate data.*

(i) Statement AY is a statement of tax rate data for Period I and Period II arranged as follows:

(A) Nominal Federal income tax rate;

(B) Nominal state income tax rate;

(C) Proportion of Federal income taxes payable which is deductible for state income tax purposes. If an allowable deduction is stated in other terms, the filing utility shall provide an estimate of the effective deduction as a percentage of Federal tax payable; and

(D) *Revenue tax rate.* If the revenue tax rate is scaled, the statement shall show approximate weighted average rates for relevant revenue levels and full supporting data.

(ii) If the filing utility serves in more than one jurisdiction for revenue or state income tax purposes, the appropriate tax rates shall be stated for each wholesale customer group at issue and for all other customers as a composite group. (*See*, Statement BA under paragraph (h)(26) for wholesale customer grouping criteria.) If there are any changes in tax rates for either Period I or Period II, the filing utility shall describe such changes and the effective date of the changes.

(26) *Statement BA—Wholesale customer rate groups.*

(i) Statement BA is a statement of wholesale customers by group for the purpose of:

(A) Allocating of the allowable costs of the filing utility to such customer groups on the basis of electric utility services rendered; and

(B) Comparing proposed revenues from each customer group with the cost of service as allocated to that group.

(ii) The number of wholesale customer groups listed shall be limited to the minimum required under the following criteria:

(A) At least one customer group shall be specified for each separate proposed wholesale rate subject to the proposed rate change.

(B) In general, all customers proposed to be served on the same rate shall be included in a common group. If there are significant differences in services provided under the same rate, the filing utility shall subdivide the common group serve by the same rate into separate customer groups characterized by the type of service provided each group and shall demonstrate whether the common rate is cost-based by means of cost-justification for each service group. Certain customer groupings, such as cooperatives or municipals, may also be utilized to facilitate purchaser evaluations of rate change proposals.

(C) In all cases customer groupings shall be selected on a basis consistent with rate design information provided in Statement BL under paragraph (h) (37).

(iii) Statement BA shall enumerate all wholesale customer rate groups, together with a brief descriptive title for each group. For example:

Group 1. Full Requirements Tariff FR-1.

Group 2. Partial Requirements Tariff PR-1.

(27) *Statement BB—Allocation demand and capability data.* Statement BB is a statement of electric utility demand and capability data for Period I and Period II, that includes consideration of the data as a basis for allocating related costs to the wholesale services at issue.

(i) For each month of Period I and Period II, and as averaged separately for the twelve months of each of those periods, the statement shall show the maximum 60-minute peak firm kilowatt demand on the power supply system of the filing utility, and the 60-minute kilowatt demands of the wholesale services that coincide with the system monthly maximum power supply demand, including for Period I the date and hour for such coincidental peak

demands. The wholesale service data for each individual customer delivery point shall include demands at delivery. The individual customer data shall be summarized and subtotaled in accordance with Statement BA customer groupings. A loss adjustment shall be shown for each wholesale customer group to reflect demand at the power supply level. The data shall be totaled to show total customer group demand at power supply level for each month and for Period I and Period II.

(ii) Data provided as required in clause (i) shall not include demands associated with interruptible power supply services, firm or nonfirm transmission wheeling services, or demands associated with other services the revenues from which are shown as revenue credits in Statement AU under paragraph (h)(21). If applicable and to the extent data are available, Period I and Period II monthly and maximum demand data shall be stated for interruptible power supply services, firm wheeling services, and nonfirm wheeling services. The statement shall also provide, to the extent data are available, firm wheeling demand data for any of the 60-minute periods that coincide with the times of power supply peak demands shown under clause (i). The filing utility shall indicate the basis of all demands, such as metered demands or contract demands, reported under this clause. For interruptible services, the statement shall provide a description of the conditions under which service may be interrupted or curtailed. Data shall include a statement of available information on actual interruptions or curtailments during a three-year period that includes Period I. If any of the proposed wholesale rates at issue are for interruptible or curtailable service, the filing utility shall provide any demand data specifically relevant to such service.

(iii) If Statement AD under paragraph (h)(4) establishes plant categories for the purpose of supporting proposed wholesale rates for firm power supply services with special characteristics, such as base load, intermediate, or peaking, Statement BB shall provide the demand data required by clause (i) in total and in separate constituent demand values consistent with the service characteristics. Constituent values shall be stated for the system demand of the filing utility, and for each applicable wholesale service group.

(iv) If Statement AD establishes plant categories for the purpose of supporting proposed wholesale rates for nonfirm power supply services, such as capacity sales, this statement shall include for each month of Period I and Period II, the monthly capability data relied on by the filing utility in developing costs allocable to such rates, with an explanation of the underlying cost allocation rationale.

(v) If Statement AD establishes production plant categories for the purpose of supporting wholesale rates based on specialized ratemaking theories, this Statement BB shall include all demand and capability data relied on by the filing utility in developing support on a cost of service basis, with appropriate explanatory material.

(vi) For each month of Period I and Period II, Statement BB shall provide any additional demand data that the filing utility believes relevant to the allocation of electric utility costs to the wholesale services at issue. All such data shall be fully supported as part of this statement, and explained in terms of the rationale and the specific application proposed.

(vii) Based upon information reported in Statements BB and BC, the filing utility shall list select months that are nomally the months of greatest significance in determining the need of the utility for power supply capability throughout the year. All twelve months may be selected, if appropriate. Selections shall take into-account any effects of local weather seasons and, particularly, the extent to which peak demands may tend to be similar in magnitude in two or more months of a weather season. The filing utility shall explain the reasons for the selections and describe the significance for the selections of seasonal variations in the weather.

(28) *Statement BC—Reliability data.* Statement BC is a statement of data

relating to reference standards of the filing utility for electric power supply reliability, and with information designed to reflect monthly availability of generating capacity reserves.

(i) For Period II, Period I, and each of the three calendar years preceding Period I, the filing utility shall state its objective reference standard of production power supply reliability, such as one day in ten years if loss of load probability is used. The filing utility shall also state the rationale underlying its choice of a reliability standard, and whether it participates with other electric utilities in the selection of a common standard on an area or pool basis. Statement BC shall identify any such participating utilities, and provide a general explanation of the basis upon which the reliability standard was jointly developed.

(ii) The filing utility shall describe how its electric generating facility construction planning and purchased power planning are related to its objective standard for production power supply reliability.

(iii) For the peak day of each month of Period II, Period I, and to the extent data are available for the peak day of each month of the three calendar years preceding Period I, Statement BC shall include tabular schedules designed to show the following:

(A) Net Peak Load in megawatts, itemized to show:

(*1*) Peak firm load, including all firm sales assured available by the available reserve capacity of the filing utility;

(*2*) All firm purchases assured available by the reserve capacity of the supplier;

(*3*) Net Peak load;

(B) Net Available Dependable Capacity in megawatts, itemized to show:

(*1*) The owned dependable capacity of the filing utility for each production plant category selected in Statement AD;

(*2*) Scheduled maintenance of owned dependable capacity of the filing utility;

(*3*) Purchased dependable capacity of the filing utility;

(*4*) Scheduled maintenance of purchased dependable capacity of the filing utility;

(*5*) Net available dependable capacity;

(C) Available Reserves in megawatts, which is the Net Available Dependable Capacity under paragraph (h)(28)(iii)(B) of this section minus Net Peak Load under paragraph (h)(28)(iii)(A) of this section.

(D) Available Reserves as a percent of peak load, which is the Available Reserves under paragraph (h)(28)(iii)(C) of this section divided by Net Peak Load under paragraph (h)(28)(iii)(A).

(29) *Statement BD—Allocation energy and supporting data.* Statement BD is a statement of electric utility energy data for Period I and Period II to be considered as based for allocating related costs to the wholesale services subject to the proposed rate change.

(i) For each month of Period I and Period II, and as totaled for the twelve months of each period, the statement shall show the megawatt-hours of firm power supply energy system required by the system of the filing utility and the megawatt-hour energy requirements of the wholesale customer groups whose services will be subject to the proposed rate change. The wholesale service data for each individual customer delivery point is to include megawatt-hours at delivery. These individual customer data shall be summarized and subtotaled in accordance with Statement BA customer groupings under paragraph (h)(26). The statement shall show a loss adjustment for each wholesale customer group to reflect energy at the power supply level. The data shall be totaled to show total customer group energy requirements at power supply for each month and for Period I and Period II.

(ii) Data provided under clause (i) shall not include energy associated with interruptible or curtailable services, or energy associated with other services revenues from which services are shown as revenue credits in Statement AU under paragraph (h)(21). Period I and Period II monthly and total energy data shall be separately stated for any such

services provided by the filing utility. If any of the proposed wholesale rates at issues are for interruptible or curtailable service, Statement BD shall provide descriptive material and energy data specifically relevant to such services.

(iii) If the utility selected subfunctional categories in Statement AD under paragraph (h)(4) for the purpose of supporting proposed wholesale rates for firm power supply services with special characteristics, such as base load, intermediate, and peaking services, the energy data required by paragraph (h)(29) (i) of this section shall be separated into constituent energy values consistent with the service characteristics, and consistent with energy-related expense categories utilized in Statement AH under paragraph (h)(8). Constituent values shall be stated for the filing utility's system energy, and for each applicable wholesale service group.

(iv) If Statement AD establishes plant categories for the purpose of supporting proposed wholesale rates for non-firm production services, or proposed wholesale rates based on specialized ratemaking theories, Statement BD shall include all energy data relied on by the filing utility in developing the support on a cost of service basis and relevant explanatory material. Energy data provided under this clause shall be consistent with related expense categories utilized in Statement AH under paragraph (h)(9).

(v) For each month of Period I and Period I, and as totaled for the twelve months of each period, Statement BD shall show the megawatt-hours generated, itemized in accordance with Statement AD production subfunctional categories, and the megawatt-hours purchased or interchanged, itemized to show each type of transaction, such as firm energy or economy interchanged energy. Such data shall be quantitatively reconciled with the system allocation energy reported in this statement, and with energy data underlying the fuel and purchase power expense reported in Statement AH.

(30) *Statement BE—Specific assignment data.*

(i) Statement BE is a statement of specific components of the electric costs of service of the filing utility for Period I and Period II. Statement BE costs of service are those apportioned among wholesale services subject to the proposed change in rates and other utility services, on a basis other than:

(A) Demand, capability, or energy data provided in Statements BB and BD;

(B) A proportional relationship based on a selected plant category or expense item for which an allocation to wholesale services is to be independently determined; or

(C) Exclusive-use commitment in Statement BF under paragraph (h)(31).

(ii) The statement shall include specific assignments considered appropriate by the filing utility. Typical cost of service components that may be specifically assigned are distribution plant [*See* examples listed in Statement AD under paragraph (h)(4)], certain total electric wages and salaries provided in Statement AI under paragraph (h)(9) such as wages and salaries for customer accounting and for customer service and information, and certain administrative and general expense items. [*See* examples listing in Statement AH under paragraph (h)(8).]

(iii) Specific assignments shall be limited to the minimum required to adequately provide for costs not otherwise appropriate allocable.

(iv) For each specific assignment, Statement BE information provided should include at least the following data:

(A) Data Source Statement, such as Statement AD—Cost of Plant;

(B) Brief descriptive component title, such as Distribution Substations or Rate Case Expenses;

(C) Total electric amount;

(D) Wholesale customer group amounts stated individually for each wholesale customer rate group identified in Statement BA under paragraph (h)(26), and stated in total for all such groups;

(E) Explanation of the basis on which assignments were made, accompanied by supporting computational detail.

(31) *Statement BF—Exclusive-use commitments of major power supply facilities.* Statement BF is a statement describing and justifying the commitment to exclusive-use for particular services of all or a stated portion of electric utility generation units or plants, or major transmission facilities.

(i) For Period I and Period II, the utility shall list each transaction in which all or a stated portion of the output of a specified applicant-owner generating unit or group of units was committe exclusively to a particular customer or group of customers, or to a power pool or similar power supply entity. For each such transaction, the utility shall provide the following information:

(A) Data source statement;

(B) Name of plant and unit designation;

(C) Name of the purchaser or power pool or other similar power supply entity;

(D) Duration of the transaction;

(E) Basis of rates or charges, stated in terms of whether a transaction reflects marginal, incremental, or fully distributed costs, the specific overall and common equity rates of return included in costs, provided on both a claimed and earned basis to the extent such information is available, the approximate date of the cost analysis on which the rates and charges were based, and any other considerations significant to the transaction;

(F) Revenue received for each month of Period I and Period II or, if applicable, monthly quantities of power and energy received or available from power pools as consideration for commitment to pool; and

(G) Proposed treatment in the cost of service determinations for the wholesale services at issue; for example, a credit of revenue to the total electric cost of service, in Statement AU under paragraph (h)(21), may be proposed to account for unit capacity sales based upon incremental capital costs. Statement BF shall include explanatory material and support for the proposed procedures.

(ii) For Period I and Period II, the utility shall list each transaction in which all, or a portion, of a major transmission facility owned by the filing utility was committed exclusively to a particular customer or group of customers. For each such transaction, the utility shall provide information similar to that required by paragraph (h)(31)(i) of this section.

(32) *Statement BG—Revenue data to reflect proposed rates.* Statement BG is statement of revenues for Period I and Period II, including those under proposed rates for wholesale services at issue.

(i) For each month of Period I and Period II, and in total for each of the two periods, the utility shall show all billing determinants and metered quantities for each delivery point or set of points that constitute an individual wholesale customer billing unit, and the result of applying each specific rate component to the billing determinants for each billing unit stated, with the total of the computed monthly bill for the customer. If the rates include a fuel clause, revenues under the fuel clause shall be computed and totaled to reflect fuel costs incured during each month of Period I and Period II; that is, the fuel clause revenues for the first month of Period I shall reflect fuel costs incurred for that month, and so on for each month of Period I and Period II. In computing fuel cost revenues, the filing utility shall determine fuel clause according to § 35.14 of this chapter.

(ii) If the form of the proposed fuel clause would produce revenues differing from those computed in accordance with paragraph (h)(32)(i) of this section, such fuel clause revenues shall be separately computed and stated for each customer for each month of Period I and Period II.

(iii) Revenue data computed in accordance with paragraph (h)(32) (i) and (ii) of this section shall be summarized for each month and in total separately for Period I and Period II, in accordance with wholesale rate groups specified in Statement BA under paragraph (h)(26). Total electric revenues shall be shown for each period

to include revenues under proposed rates for all such wholesale customer rate groups.

(iv) For Period I and as estimated for Period II, the utility shall summarize all billing determinants and revenues received from interruptible or curtailable services. Billing determinants and revenue data shall be consistent with interruptible demand and energy data in Statements BB and BD. This statement shall include an explanation of the extent to which interruptible or curtailable revenues are or are not included in revenue credits at Statement AU under subparagraph (h)(21).

(33) *Statement BH—Revenue data to reflect present rates.* Statement BH is a statement of revenues for Period I and Period II, including those under present rates for wholesale services at issue, and for total electric service to reflect such revenues for wholesale services. This statement shall be prepared to include date consistent with criterial specified for presentation of revenue under proposed rates at Statement BG under paragraph (h)(32).

(34) *Statement BI—Fuel cost adjustment factors.* Statement BI is a statement of monthly fuel cost adjustment factors under the proposed rates and under the present rates, for Period I and Period II.

(i) If the proposed rate schedule embodies a fuel cost adjustment clause, the utility shall show detailed derivations of fuel cost adjustment factors computed to reflect fuel cost incurred during each month of Period I and Period II. Fuel cost adjustment factors are those required for revenue determinations in accordance with paragraph (h)(32)(i) of Statement BG.

(ii) If additional proposed fuel clause revenue data are reported in accordance with paragraph (h)(32)(ii) of Statement BG, this statement shall show detailed derivation of applicable monthly fuel adjustment factors.

(iii) If the present rate includes a fuel cost adjustment clause, the utility shall show detailed derivations of fuel cost adjustments factors for each month of Period I and Period II. Statement BI shall include derivations for all monthly factors required in the computation of present fuel clause revenues reported in Statement BH. Statement BI shall include an explanation of the differences between the present and proposed fuel clauses.

(iv) All fuel cost adjustment factors shall be cost-based. The utility shall make a computational showing that shall develop adjustment factors in a manner consistent with the requirements of § 35.14 of this chapter. The supporting detail shall include cost by type of fuel and mode of electric energy generation, and shall show separately by the type of transaction the allowable fuel clause cost component of purchased or interchanged energy. All fuel cost data shall be consistent with that included in operation and maintenance expenses in Statement AH under paragraph (h)(8), and particularly the expense data reported in accordance with paragraph (h)(6)(v) of Statement AH.

(35) *Statement BJ—Summary Data Tables.* Statement BJ is a tabular summary of Period I and Period II data from specific cost of service statements in this paragraph. The statement shall summarize the Period I and Period II data from the following provisions in paragraph (h):

(i) *Single data entries:*

(A) Statement AD—(h)(4) (i) and (ii);

(B) Statement AE—(h)(5) (i) and (ii);

(C) Statement AF—(h)(6) (i) through (x);

(D) Statement AG—(h)(7) (i) through (vi);

(E) Statement AH—(h)(8) (ii) through (iv);

(F) Statement AI—(h)(9)(ii);

(G) Statement AJ—(h)(10)(i);

(H) Statement AK—(h)(11)(i);

(I) Statement AL—(h)(12) (i) and (ii);

(J) Statement AM—(h)(13);

(K) Statement AN—(h)(14);

(L) Statement AP—(h)(16) (i) through (vi);

(M) Statement AQ—(h)(17) (i) through (iii);

(N) Statement AR—(h)(18) (i) through (iv);

(O) Statement AS—(h)(19);

(P) Statement AT—(h)(20);
(Q) Statement AU—(h)(21);
(R) Statement AV—(h)(22)(i)(A);
(S) Statement AW—(h)(23);
(T) Statement AY—(h)(25)(i);
(ii) *Multiple data entries:*
(A) Statement BB—(h)(27) (i) through (vi);
(B) Statement BD—(h)(29) (i) through (iv);
(C) Statement BE—(h)(30)(iv) (B), (C), and (D);
(D) Statement BG—(h)(32)(iii);
(E) Statement BH—(h)(33).

(36) *Statement BK—Electric utility department cost of service, total and as allocated.* Statement BK is a statement of the claimed fully allocated cost of service of the filing utility developed and shown for Period I and Period II. Statement BK shall include analytical support for each rate proposed to be differentiated on a time-of-use basis. The filing utility shall also include any marginal or incremental cost information that is required to support rate proposal developed on a marginal or incremental cost basis. Statement BK shall show allocations of fully distributed costs to the wholesale services subject to the proposed rate change and is accompanied by a comparison allocated costs with revenues under the proposed rates.

(i) The fully distributed cost of service and the allocations thereof shall be based upon data provided in the accompanying detailed statements required under this section and additional data which the filing utility may submit and support in connection with this statement. The cost of service data of the filing utility shall conform to these requirements;

(A) The total electric rate base and cost of service shall be itemized and summarized by major functions and in a format designed to facilitate review and analysis.

(B) Based on the total electric rate base and cost of service, and on allocated or assigned component elements, the cost of service for each Statement BA wholesale customer rate group under paragraph (h)(26) shall be itemized and summarized by major functions in a format consistent with that shown for total electric.

(C) The costs of service data for total electric and for each of the wholesale customer groups shall include data that shows the return and the income taxes by the elements and in total, based upon the rate of return claimed by the applicant in Statement AV under paragraph (h)(22).

(D) The fully distributed cost of service study of the filing utility shall disclose the principal determinants for allocation of total electric costs among the wholesale customer groups, including but not limited to the following:

(*1*) Computations showing the energy responsibilities of the wholesale services, with supporting detail;

(*2*) Computations showing the demand responsibility of the wholesale services, with supporting detail; and

(*3*) Computations showing the specific assignment responsibilities of the wholesale services with supporting detail.

(ii) For the total electric service and for each wholesale customer rate group, the fully distributed cost of service shall be compared with the revenues under the proposed rates. Based on the comparison, the statement shall show the revenue excess or deficiency and the earned rate of return computed for the total electric service and for each wholesale customer rate group.

(iii) The work papers and additional explanatory material needed specifically for Statement BK of a Period II submittal shall be indexed according to the names of witnesses and shall include index references to the specific elements of Statement BK supported by each segment of the material. All working papers shall be assigned page numbers to assist in review and referencing.

(iv) Statement BK shall include a tabular comparison of Period II total electric fully distributed cost items with those of Period I. The comparisons shall show item amounts for each of the two periods, and shall also show Period II

item amounts as percentages of equivalent items for Period I. Comparisons shall include at least the following items, accompanied by explanatory notes with respect to significant variations among the comparative percentages:

(A) Rate Base;

(B) Production Expenses;

(C) Transmission Expenses;

(D) Customer Accounting Customer Service and Information, and Sales Expenses;

(E) Depreciation Expenses;

(F) Taxes Except Income and Revenue;

(G) Income Taxes Claimed

(H) Revenue Taxes; and

(I) Return.

(37) *Statement BL—Rate design information.* In support of the design of the proposed rates, the filing utility shall submit the following material:

(i) A narrative statement describing and justifying the objectives of the design of the proposed rate. If the purpose of the rate design is to reflect costs, the narrative shall state how that objective is achieved, and shall be accompanied by a summary cost analysis that would justify the rate design, including any discounts or surcharges based on delivery voltage level or other specific considerations. Such summary cost analysis shall be consistent with, and derived from, the data in cost of service Statement BK. If the rate design is not intended to reflect costs, whether fully distributed, marginal, incremental, or other, a statement shall be provided to justify the departure from cost-based rates.

(ii) If the billing determinants, such as quantities of demand, energy, or delivery points, are on different bases than the cost allocation determinants supporting such charges, an explanation shall be submitted setting forth the economic or other considerations that warrant such departure. The information shall include at least the following:

(A) The individual rates for the demand, energy and customer charges do not correspond to the comparable cost classifications supporting such charges, a detailed explanation shall be submitted stating the reasons for the differences.

(B) If the rates being charged contained more than one demand or energy block, a detailed explanation shall be submitted indicating the rationale for the blocking and the considerations upon which such blocking is based, including adequate cost support for the specific blocking.

¶ 32,056 High-Cost Natural Gas Produced from Tight Formations

45 F. R. 13427 (February 28, 1980)

18 CFR Part 271

[Docket No. RM79-76]

High-Cost Natural Gas Produced From Tight Formations

February 20, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission hereby gives notice that in the Interim Rule and Request for Further Comment issued on February 20, 1980, in Docket No. RM79-80, entitled High-Cost Natural Gas Produced From Tight Formations, it proposed to establish a special incentive price for certain gas produced from tight formations which do not qualify under the provisions of the Interim Rule. The proposal would extend a special incentive for gas produced from designated tight formations from wells, the surface drilling of which began before July 16, 1979, if, *inter alia*, the well was not completed for production in the designated tight formation before July 16, 1979. *See* the Interim Rule and Request for Further Comment published in this issue of the **Federal Register** for further discussion of the proposal and the interim rule.

DATE: Written comments by March 28, 1980.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Send 14 copies of any comments and reference Docket No. RM79-76.

FOR FURTHER INFORMATION CONTACT:

Teresa Ponder, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-8151.

or

Howard Kilchrist, Director, Division of NGPA Compliance, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-8585.

SUPPLEMENTARY INFORMATION:

I. Background

In an Interim Rule and Request for Further Comments issued February 20, 1980, in Docket No. RM79-76, the Commission issued interim rules implementing section 107(b) and (c)(5) of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3317). Section 107 of the NGPA permits the Commission to identify gas which is produced under extraordinary risk or cost and to establish the maximum lawful price "necessary to provide reasonable incentives for the production" of such gas. The interim rule established gas produced from certain new wells in tight formations as a category of high-cost natural gas subject to incentive pricing and established the procedures for identifying such gas. In the Interim Rule and Request for further comment the Commission also sought further comment on whether incentive prices should be extended to most other tight formation gas.

Specifically, the Commission gave notice that it is considering establishing incentive prices for gas produced from designated tight formations which does not qualify as new tight formation gas but which is produced from wells which were not completed for production in the tight formation prior to July 16, 1979. The following new category (and definition) is proposed:

§ 271.703 Definitions.

* * * * *

(c) "Recompletion tight formation gas" is natural gas:

(1) Which is produced from a designated tight formation through a well, the surface drilling of which was begun before July 16, 1979, if such well

was not competed for production from such formation before July 16, 1979; and

(2) For the first sale of which a negotiated contract price is effective.

The Commission also proposes to permit a price ceiling based on the section 103 maximum lawful price with respect to "recompletion tight formation gas." The proposal would read as follows:

§ 271.702 Maximum lawful prices.

* * * * *

(b) *Tight formation gas.* * * *

(2) *Recompletion tight formation gas.* The maximum lawful price, per MMBtu, for recompletion tight formation gas shall be the lesser of:

(i) The negotiated contract price; or

(ii) The maximum lawful price specified for Subpart C of this Part 271 in Table I of § 271.101(a).

See the Interim Rule and Request for further comment in this issue of **Federal Register** for further description of the interim rule and the proposal.

II. Public Procedures

Interested persons may submit comments by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before March 28, 1980. Each person submitting a comment should indicate that the comments are being submitted in Docket No. RM79-76, and should give reasons including any supporting data for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concering the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

A date and location of further hearings on this rulemaking may be announced in the near future. The proposed regulations will not be promulgated as final regulations until the Commission has had an opportunity to receive oral presentation of relevant data, views and arguments.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

¶ 32,057 Section 206(d) Exemption for Small Industrial Boiler Fuel Facilities from the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

45 F. R. 15555 (March 11, 1980)

18 CFR Part 282

[Docket No. RM79-48]

Section 206(d) Exemption For Small Industrial Boiler Fuel Facilities from the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978; Public Hearings

AGENCY: Federal Energy Regulatory Commission.

ACTION: Futher Notice of Proposed Rulemaking and Public Hearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby issues a further notice of proposed rulemaking and public hearings in the above-captioned docket. This proposal, if adopted as a final rule and not disapproved by Congress, would exempt form incremental pricing the natural gas used as boiler fuel by those industrial facilities whose boiler fuel usage of natural gas averages 300 thousand cubic feet (Mcf) per day or less.

DATES: Requests to participate by March 24, 1980. Hearing dates: March 26, 1980, in Washington, D.C.; April 1, 1980, in Los Angeles, California. Comments due: April 4, 1980.

ADDRESSES: Requests to participate and written comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. [Reference Docket No. RM79-48]. Hearing locations:

Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (March 28, 1980, beginning at 9:30 a.m.)

State Building, Auditorium, 107 South Broadway, Los Angeles, California 90016 (April 1, 1980, beginning at 9:00 a.m.)

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8079.

SUPPLEMENTARY INFORMATION:

Issued: March 6, 1980.

I. Background

Section 206(a) of the Natural Gas Policy Act of 1978 (NGPA) grants an exemption from incremental pricing surcharges for natural gas used as boiler fuel by "small" industrial boiler facilities which were in existence on November 9, 1978, the date of enactment of the NGPA. (These facilities are hereinafter referred to as "existing facilities"). Section 206 also provides a two-stage process for defining "small" facilities granted this exemption. The first, or interim, exemption applies for the time period up to May 9, 1980, at which time the second, or permanent, small facility definition must be in place. Under the interim exemption rule, a facility is considered to be "small", hence exempt, if its use of natural gas as boiler fuel was a daily average of 300 thousand cubic feet (Mcf) or less during each month of a base period determined by the commission. The Commission determined, in the final regulations in Docket No. RM79-14 implementing this portion of the incremental pricing program, to use calendar year 1977 as the base period.

Under the "permanent exemption" rule for small boiler facilities, the Commission is required to use calendar year 1977 as the base period. As a result of data supplied by the Energy Information Administration (EIA), the Commission, in a Notice of Proposed Rulemaking issued today in Docket No. RM80-24, *Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt from Incremental Pricing under the Natural Gas Policy Act of 1978*, has determined that section 206 requires that the threshold for the

permanent exemption be 300 Mcf per day, the figure that is now used as the threshold for the interim exemption.

On September 28, 1979, the Commission issued a Notice of Proposed Rulemaking (44 FR 57783, October 5, 1979) to exempt from incremental pricing surcharges natural gas used as boiler fuel in small industrial facilities which either came into existence after November 9, 1978, or which may come into existence at some time in the future. These facilities were referred to in the September 28th proposal as "new" facilities.

As stated in the September 28th Notice, both the statute and the legislative history are silent as to the reason why the Congress determined to grant an exemption from the incremental pricing program to existing small industrial boiler facilities, and, apparently, not to new small industrial boiler facilities. The Commission stated in the September proposal that, for purposes of implementing the incremental pricing program, it appeared inconsistent and inequitable to distinguish between small boiler facilities which were in existence on November 9, 1978, and those which came into existence after that date. Therefore, the Commission proposed to enlarge the class of exempt small boiler facilities to include new small boiler facilities.

A Further Notice of Proposed Rulemaking is issued in this docket for two reasons. First, only eight written comments were received in response to the September 28th Notice. In addition, only one firm, Northern Illinois Gas Company, participated in the public hearing which was held on the proposed rule on October 22, 1979. Thus, the Commission seeks additional comments to supplement the record developed on the September proposal with respect to an exemption from incremental pricing surcharges for new small industrial boiler facilities.

Secondly, further notice is issued in this docket in order to expand the scope of the proposed exemption. As stated in Order No. 49–A, the order on rehearing issued in Docket No. RM79-14 (45 FR 767, January 3, 1980), the Commission has received a number of petitions pursuant to section 502(c) of the NGPA and § 1.41 of the Commission's regulations requesting adjustments to the regulations in Order No. 49 which govern the existing small boiler facility exemption. Each petition concerns a facility whose usage of natural gas as a boiler fuel has dropped below the 300 Mcf per day threshold since 1977.

As stated in Order No. 49–A, the Commission believes a generic rule would be the most appropriate method of dealing with all facilities which have reduced their boiler fuel usage to below the 300 Mcf per day threshold since 1977. The Commission believes that, for purposes of imposing incremental pricing surcharges, it may be inconsistent and inequitable to use a 1977 base period for "existing" facilities when it is not an accurate measure of the facility's present gas usage. Thus, the commission hereby proposes to treat an "existing" facility, which for a period of twelve consecutive months consumes an average of 300 Mcf per day or less for boiler fuel in each of those months, as a "newly" small facility, and thus eligible for an exemption as a small facility.

The regulations below are being proposed pursuant to section 206(d) of the NGPA. Thus, if the regulations are adopted by the Commission as a final rule, they will be submitted to the Congress for review prior to taking effect. After the regulations are submitted to each House of Congress, they may take effect following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30 day period.

II. Discussion

A. Regulations Proposed. The Commission proposes to implement the discretionary exemption described above for small facilities through adoption of the following qualifying test: for a period of twelve consecutive months, the facility would have to consume no more than an average of 300

Mcf per day for boiler fuel in any month. The Commission also proposes that the exemption would continue to be effective as long as consumption does not exceed an average of 300 Mcf per day in any month.

If a facility does not have a twelve month consumption record, the facility may qualify for an exemption, for the time period up until it has a twelve month record, on the basis of its capacity determined on the nameplate rating(s) of its boiler(s), as discussed in section (B) below.

The Commission proposes to use 300 Mcf per day as the threshold for determining "small". This threshold is the same as that threshold required by section 206(a)(1) of the NGPA for the interim exemption and as that proposed by the Commission pursuant to section 206(a)(2) for the permanent exemption for existing small boiler facilities.[1] Thus, a new facility which used an average of 300 Mcf per day or less of natural gas as boiler fuel would be eligible for an exemption from the incremental pricing program. Similarly, an existing industrial boiler fuel facility which is non-exempt based on a 1977 consumption record could qualify for an exemption on the basis of experience in a later twelve month period.

B. Method for Determining Size of a Boiler Facility. As the Commission noted in the September 28th Notice, the most significant question that must be addressed in proposing to enlarge the class of small boiler facilities eligible for an exemption from incremental pricing surcharges is how to determine the size of such facilities.

In the September Notice the Commission proposed that a facility's size be determined by using nameplate rated capacity. Specifically, the proposal was to determine the size of a facility by totaling the nameplate ratings of all of the facility's boilers which have gas burning capability, and multiplying that number by 16. This approach assumed that all gas-fired boilers would be operated at rated capacity for an average of 16 hours per day.

Several of the comments that were submitted in response to the September Notice objected to the above-described formula. The commenters pointed out that it is not unusual for a facility to have at least one back-up boiler. In addition, it was argued that there is a wide variance in the number of hours each facility's boilers are operated and a 16 hour per day average is arbitrary and frequently would not reflect actual operating conditions.

The Commission is aware that the use of nameplate rating and a 16 hour per day average may overstate or understate actual gas usage. Accordingly, we herein propose the twelve month base period approach noted above. Under this approach, a facility that does not qualify for the statutory exemption for existing small industrial boiler facilities would be eligible for a small boiler facility exemption if it has consumed no more than an average of 300 Mcf per day in each of the twelve consecutive months preceding its sumission of an affidavit stating its eligibility for exemption. The Commission believes that use of a twelve month base period to determine eligibility is consistent with the statutory exemption for small boiler facilities, which uses a twelve month period. In addition, the Commission is concerned that use of a base period of less than twelve months might result in distortions due to the seasonal availability of gas on many systems and to seasonal patterns of usage.

[1] Section 206(a)(2) of the NGPA requires that, in the permanent exemption for existing small boiler facilities, the Commission shall lower the 300 Mcf threshold if necessary to assure that the natural gas used in 1977 as boiler fuel by exempted existing small industrial boiler fuel facilities did not exceed five percent of the total volume of natural gas that was transported in interstate pipelines and used as a boiler fuel in 1977. The proposed regulations contain a provision which would require that, in the event the 300 Mcf threshold is lowered when the permanent exemption proposed in Docket No. RM80-24 for existing small boilers becomes effective, the threshold for exemption for small boiler facilities as proposed in this docket also would be lowered.

For a facility which either does not yet have twelve months of usage or has twelve months of experience which, due to new installations or modifications to the facility's boilers, overstates actual current gas consumption, the facility's capacity could be determined in accord with the formula based on rated capacity, as originally proposed in the September 28th Notice. This method for determining a facility's eligibility for an exemption could be used only until such time as the facility had twelve consecutive months of actual experience on which to determine its continued exemption eligibility. At such time an exemption affidavit must be refiled if the facility has consumd an average of 300 Mcf per day or less for boiler fuel in each month during this twelve month period. If, at any time during the twelve month period, the facility exceeds the 300 Mcf per day threshold for boiler fuel use of natural gas, the Commission and the facility's supplier must be notified in accord with § 282.205 of the Commission's regulations and the facility will lose its exemption, effective the first day of the following month.

The Commission is aware that the nameplate formula for determining the capacity of an industrial boiler facility, because of its rigidity, may result in an inaccurate reflection of some facilities' actual gas usage. The Commission therefore requests comments on this aspect of the proposal. Specifically, comments are requested on the 16-hour-day number and, if commenters suggest using another number, data in support of the proposed number are requested. Comments also are requested on alternatives to the rated capacity component of the formula that would be administratively feasible.

C. Filing the Exemption Affidavit. Consistent with the Commission's approach with respect to other exemptions under the incremental pricing program, we are proposing that a facility would obtain an exemption under this rule by filing an affidavit. Those facilities with less than twelve months of gas usage would obtain an exemption on the basis of the facility's capacity. The exemption would be effective until the facility exceeds the 300 Mcf per day threshold in any month, at which time the Commission and the supplier must be notified of the changed circumstances in accordance with § 282.205, or until the facility has twelve consecutive months of actual experience at which time an exemption affidavit would have to be refiled. Failure to refile the exemption affidavit at the end of the twelve month period would terminate the exemption.

Exemptions based on gas usage for a twelve month period would be effective until such time as the facility's average usage in any month exceeds 300 Mcf per day. At such time, the owner or operator of the facility would be obliged to notify the facility's natural gas supplier and the Commission regarding the change of circumstances with respect to the facility, in accordance with § 282.205 of the Commission's regulations, and the facility would become subject to the incremental pricing regulations and surcharges.

III. Summary of the Proposed Rule

The proposed regulation would add a new § 282.210 for small industrial boiler facility exemptions to Part 282 of the Commission's regulations.

The new § 282.210(b)(1) would exempt facilities which did not consume more than an average of 300 Mcf per day for boiler fuel during any month of the preceding twelve month period. The 300 Mcf per day figure would be used until such time as the permanent exemption for existing small boiler facilities (section 206(a)(2)(A) of the NGPA) becomes effective. At that time, the number that would be used as the threshold for the permanent exemption would also be used for determining exemptions for small boiler facilities under § 282.210 of the regulations. As previously noted, the Commission has proposed, in Docket No. RM80-24, that the threshold for the permanent exemption remain at 300 Mcf per day.

The new § 282.210(b)(2) would be used by those industrial boiler facilities

which do not have twelve consecutive months of actual experience, as required by § 282.210(b)(1). The size of such a facility would be determined by using the nameplate rated capacity for all boilers within the facility which have the capability to burn natural gas. For a boiler rated in terms of Mcf per hour, the boiler's capacity would be obtained by multiplying the nameplate rating by 16. If a boiler is rated in terms of MMBtu per hour, before being multiplied by 16, the rating would first be converted to Mcf per hour using a conversion factor of one Mcf per one MMBtu. For a facility which has more than one boiler with gas fired capability, the facility's total capacity would be the sum of the capacities for each boiler which has the capability to burn gas. Any facility with a total capacity of 300 Mcf per day or less would be eligible for an exemption from incremental pricing surcharges for its boiler fuel use of natural gas.

Those facilities that file for an exemption based on rated capacity would be required to refile an exemption affidavit after the facility has twelve consecutive months of actual experience. The facility would continue to be eligible for an exemption only so long as actual consumption averaged 300 Mcf per day or less during each month.

If the rule proposed herein becomes effective, a facility could obtain an exemption as a small boiler facility by following the procedures in § 282.204 of the Commission's regulations. That exemption would not be retroactive. Under § 282.204(d)(7)(ii) a facility would be exempt from incremental pricing as of the beginning of the first full month following the date the exemption affidavit is filed with the Commission and received by the facility's natural gas supplier.

IV. Comments Requested

The Commission specifically requests comments on whether the proposal described above to grant an exemption to facilities which consume less than a threshold amount of natural gas for a twelve month period would serve as an incentive for facilities to limit their use of natural gas as boiler fuel simply to gain an exemption from incremental pricing surcharges for the level of use below the threshold amount. The Commission is concerned that such a provision might serve as an incentive for the consumption of boiler fuels, other than natural gas, which are in short supply. Comments are requested as to alternatives available to the Commission to avoid creating this incentive. At present, the only alternative approach would appear to be the making of determinations as to the eligibility of existing facilities for exemption on the basis of reduced usage on a case-by-case basis.

V. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM79–48. An original and 14 copies should be filed. All comments received on or before April 4, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection through the Commission's Office of Congressional and Public Affairs, Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearings.* Public hearings on this proposed rule will be held in Washington, D.C., on March 28, 1980, beginning at 9:30 a.m. and in Los Angeles, California, on April 1, 1980, beginning at 9:00 a.m. The Washington hearing will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426. The Los Angeles hearing will be held in the Auditorium of the State Building, 107 South Broadway, Los Angeles, California 90016. The hearings

will be held for the purpose of receiving oral comments on three proposals of the Commission with respect to the incremental pricing regulations: the proposal herein; the interim rule issued on December 27, 1979, in Docket No. RM80–16, *Disclosed Estimation Methodology Approach for Determination of Volumes of Natural Gas Used for Exempt Purposes Under the Incremental Pricing Program;* and the proposed rule issued today in Docket No. RM80–24, *Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt from Incremental Pricing under the Natural Gas Policy Act of 1978.*

Requests to participate in a hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, no later than March 24, 1980, and should indicate for which hearing the request is made. Requests should reference Docket No. RM79–48, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in a public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in each hearing will be available in the Commission's Division of Public Information, Office of Congressional and Public Affairs, three days before the hearing and will be available at the site of the hearing on the morning it is convened.

Members of the hearing panel will be designated by the Chairman of the Commission. The hearings will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at each hearing. Transcripts of the hearings will be available through the Commission's Division of Public Information, Office of Congressional and Public Affairs.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, as set forth below.

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.204 is amended in clause (d)(3)(i) by adding new clauses (J) and (K) to read as follows:

§ 282.204 Obtaining an exemption.

* * * * *

(d) * * *

(3) * * *

(i) * * *

(J) Does your facility meet the following three requirements?

(*1*) your industrial boiler fuel facility does not qualify for an exemption under question (A);

(*2*) your facility has twelve consecutive months of actual experience;

(*3*) on the basis of records, documents, or data in your possession, your facility's average daily consumption of natural gas for boiler fuel, for each month in the twelve months preceding the filing of the affidavit, was 300 Mcf per day or less.

(K) Does your facility have less than twelve consecutive months of actual experience, and does your facility, on the basis of records, documents or data in your possession, have a total capacity, as determined in accord with § 282.210(b)(2), which is no more than 300 Mcf per day?

* * * * *

2. The table of sections for Part 282 is amended to add a new § 282.210 entitled *"Exemptions for small industrial boiler fuel facilities under section 206(d)."*

3. Part 282 is amended by adding new § 282.210 to read as follows:

§ 282.210 Exemptions for small industrial boiler fuel facilities under section 206(d).

(a) *General Rule.* Natural gas used for boiler fuel in a small industrial boiler fuel facility not eligible for an exemption under § 282.203(a) shall be exempt from incremental pricing under this part.

(b) *Definition.* For purposes of this section, a small industrial boiler fuel facility is an industrial boiler fuel facility which:

(1) Did not consume more than the lesser of: (i) an average of 300 Mcf per day for boiler fuel during any month of the preceding twelve consecutive months; or (ii) the volume of natural gas determined by the Commission in accordance with section 206(a)(2)(B)(ii) of the NGPA; or

(2) If the facility does not have twelve consecutive months of actual experience upon which to determine its eligibility, has a total capacity, as determined in accordance with paragraph (c), which is no more than the lesser of: (i) 300 Mcf per day; or (ii) the volume of natural gas determined by the Commission in accordance with section 206(a)(2)(B)(ii) of the NGPA.

(c) *Capacity.* (1) *Definition.* For the purposes of this part, the capacity of a boiler which has the capability to burn natural gas is the volume of natural gas, stated in Mcf per day, which would be consumed if the boiler were operated at nameplate rated capacity for a continuous 16 hour period.

(2) *Rating in terms of MMBtu.* For purposes of this part, the capacity of a boiler whose nameplate rated capacity is stated in terms of MMBtu per hour shall be obtained by converting the MMBtu rating to an Mcf equivalent. This conversion shall be based on a conversion factor of one MMBtu to one Mcf.

(3) *Total capacity of a facility.* For purposes of this part the total capacity of an industrial boiler fuel facility shall be the sum of the capacities of all boilers within the facility which have the capability to burn natural gas.

(d) *Obtaining an exemption.* Exemptions under this section may be obtained in accord with the procedures prescribed in § 282.204.

(e) *Exemption on basis of nameplate rating.* The owner or operator of a facility which obtains an exemption on the basis of its nameplate rating under subparagraph (b)(2) must file a new exemption affidavit as described in § 282.204(d) at such time as the facility has twelve consecutive months of actual experience.

(f) *Termination of exemption.* An exemption under this section shall be valid until such time as actual consumption of natural gas consumed as boiler fuel in the small industrial boiler fuel facility exceeds an average of 300 Mcf per day in any month. In this circumstance, the owner or operator of the facility must file a notification with its natural gas supplier and the Commission pursuant to § 282.205.

¶ 32,058 Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt from Incremental Pricing Under the Natural Gas Policy Act of 1978

45 F. R. 15559 (March 11, 1980)

18 CFR Part 282

[Docket No. RM 80-24]

Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt From Incremental Pricing Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby issues a proposed rulemaking relating to the permanent exemption from incremental pricing required by section 206(a)(2) of the Natural Gas Policy Act of 1978 (NGPA) for small existing industrial boiler fuel users. The Commission proposes herein that the threshold for the permanent exemption, established in accordance with section 206(a)(2)(B) of the NGPA, be 300 thousand cubic feet (Mcf) per day, the figure that is now used as the threshold for the interim exemption.

DATES: Requests to participate by March 24, 1980. Hearing dates: March 28, 1980, in Washington, D.C.; April 1, 1980, in Los Angeles, California. Comments due: April 4, 1980.

ADDRESSES: Requests to participate and written comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

[Reference Docket No. RM80-24].

Hearing Locations:

Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (March 28, 1980, beginning at 9:30 a.m.)

State Building, Auditorium, 107 South Broadway, Los Angeles, California 90016 (April 1, 1980, beginning at 9:00 a.m.)

FOR FURTHER INFORMATION CONTACT:

0Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8079

Issued: March 6, 1980.

I. Introduction

By means of this rulemaking, the Commission proposes to discharge its ministerial function under Title II of the NGPA by promulgating a permanent exemption from the incremental pricing program for small industrial boiler fuel facilities.

Title II of the Natural Gas Policy Act of 1978 (NGPA) requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as boiler fuel in large industrial facilities. "Small" industrial boiler fuel users are granted a statutory exemption from the incremental pricing program. Section 206(a)(2) of the NGPA directs the Commission to prescribe and make effective a permanent rule exempting "small existing industrial boiler fuel users" by May 9, 1980. During the period prior to the effectiveness of a permanent exemption rule, section 206(a)(1) provides for an interim exemption for "small" users, which are defined as those using a monthly average of 300 thousand cubic feet (Mcf) or less per day.

The Commission, in this Notice of Proposed Rulemaking, solicits public comment on its determination with respect to the permanent exemption rule for small existing industrial boiler fuel users provided for by Congress in section 206(a)(2).

The basic issue is the threshold size for the "small" boiler category. In addition, some other related issues that have arisen during the Commission's Title II implementation activities also will be addressed in this rulemaking.

The rule is proposed pursuant to section 206(a)(2), which states in full:

(2) Permanent exemption—

(A) General rule—Not later than 18 months after the date of the enactment of this Act, the Commission shall prescribe and make effective a rule providing for the exemption of any small industrial boiler fuel facility from the rule required under section 201 (including any amendment under section 202 to such rule).

(B) Definition—For purposes of this paragraph, the term "small industrial boiler fuel facility" means any industrial boiler fuel facility in existence on the date of the enactment of this Act that had an average per day use of natural gas as a boiler fuel during the month of peak use during calendar year 1977 which did not exceed the lesser of—

(i) 300 Mcf; or

(ii) such average daily rate of use during a month of peak use as the Commission determines in such rule is necessary to assure that the volume of natural gas estimated by the Commission to have been used for boiler fuel during calendar year 1977 by facilities which are exempted under this paragraph does not exceed 5 percent of the total volume of natural gas estimated by the Commission to have been used for boiler fuel transported by interstate pipelines and used during calendar year 1977 as a boiler fuel.

Under section 206(a)(2)(B), the Commission must, in effect, identify the average daily usage level that would make 95 percent of the natural gas transported by interstate pipelines and used as boiler fuel subject to incremental pricing. The statute specifies 1977 as the base year. The Commission is then directed to adopt, as the threshold for the permanent exemption, the lower of (1) 300 Mcf per day, or (2) the volumetric threshold required to achieve 95 percent coverage.

The regulations below are also being proposed to clarify the definition of those facilities that were in existence on November 9, 1978, and thus eligible to be considered for the permanent small boiler facility exemption.

II. EIA Determination

In November 1978, the Commission requested that the Energy Information Administration (EIA) of the Department of Energy undertake the collection and analysis of data in order to determine the volumetric threshold that would achieve 95 percent coverage of industrial boiler fuel use, as specified by section 206(a)(2)(B) of the NGPA. This task was undertaken in conjunction with other data collection requirements necessitated by the NGPA.

By a memorandum transmitted to the Commission on February 26, 1980, the Administrator of the EIA informed the Commission that:

> Within the constraints resulting from the accuracy of the data provided to us, we are 99 percent confident that the volume of natural gas transported by interstate pipelines and used by small industrial facilities as a boiler fuel during calendar year 1977, whose average per day use during the month of peak use did not exceed 300,000 cubic feet, is less than 5 percent of the total volume of natural gas transported by interstate pipelines and used during calendar year 1977 as a boiler fuel.

The following table is produced from data included in the memorandum from the Administrator of the EIA to the Commission:

Table I—*Estimated Boiler Fuel Use by Small Industrial Facilities From Interstate Pipelines as a Percent of Total Interstate Boiler Fuel Use for 1977*

Industrial boiler fuel use—average Mcf per day month of peak use	Estimated cumulative volume	Estimated cumulative percent	Percent cumulative coefficient of variation
0 to 50	2,403,367	0.4	17.3
51 to 100	8,750,500	1.4	9.5
101 to 150	11,008,993	1.8	7.6
151 to 200	14,359,222	2.4	5.8
201 to 250	14,951,315	2.5	5.6
251 to 300	16,573,838	2.7	5.2
Over 300	394,073,824	64.8	3
Total industrial		67.5	
Commercial and electrical generation		32.5	
Total boiler fuel		100.0	

Source: Energy Information Administration, U.S. Department of Energy *Report to Determine 5 Percent Exemption to Incremental Pricing.* (Memorandum from L. E. Moses to G. R. Hall, February 26, 1980, Attachment 2.)

Table I indicates that 2.7 percent of total interstate boiler fuel use in 1977 was consumed by industrial facilities whose average daily use was 300 Mcf or less. The Commission will use this figure to establish whether the 300 Mcf or 95 percent tests will determine the

threshold for small boilers exempt from the incremental pricing program. The determination by EIA that the 300 Mcf test governs is based upon a computation which excludes fuel use in commercial facilities and for electrical generation purposes.

When boiler fuel consumption of natural gas is not broken out by end-use categories prior to computing the 95 percent threshold level, a very different pattern of consumption by size of boiler emerges compared with that portrayed in Table I. This is shown by Table II which disaggregates total boiler fuel use of natural gas delivered by interstate pipelines into various size categories without regard to end-use. Figures similar to those in Table II were provided to the Commission by EIA in a series of interim reports. However, its final report reflects adjustments by EIA to exclude non-industrial boiler fuel use. Because separate industrial and non-industrial boiler fuel volumetric data were not collected, EIA's adjustments were based on other information and judgments about non-industrial user profiles.

Table II—*Boiler Fuel Use as a Percent of Interstate Pipeline Volumes for 1977*

Boiler use volume range Mcf per day peak day range	Volumes Mcf	Percent
0 to 50 Mcf	47,881,923	7.1
51 to 100 Mcf	28,984,717	4.3
101 to 150 Mcf	19,275,418	2.9
151 to 200 Mcf	20,488,771	3.0
201 to 250 Mcf	9,784,170	1.4
251 to 300 Mcf	10,758,441	1.6
Subtotal: 0 to 300 Mcf	137,206,838	20.3
Over 300 Mcf	538,371,594	79.7
Total	675,578,432	100

Table II shows that if non-industrial boiler fuel volumes are not subtracted, the 95 percent computation would bring the small boiler threshold figure to lower than 50 Mcf per day. On a total end use basis, 7.1 percent of 1977 interstate boiler fuel use volumes were was consumed in facilities smaller than 50 Mcf per day, and only about 80 percent of total 1977 interstate boiler fuel volumes were consumed by facilities larger than 300 Mcf per day.[1]

The Commission agrees with EIA's view that the Congressional intent of section 206(a) was that industrial boiler fuel usage should be segregated. The Commission relies on EIA's data-gathering expertise, statistical analysis experience, and judgments on how to perform the computations necesssary to derive the required threshold. The Commission merely notes, for the information of commenters and others who may be interested, the nature of the EIA analysis of the basic data used for determining the 95 percent threshold level.

On the basis of the data obtained and analyzed by EIA, the Commission determines that pursuant to section 206(a)(2) of the N.G.P.A., a permanent exemption from the incremental pricing program established by Title II of the NGPA is provided for all industrial boiler fuel facilities whose average monthly consumption of boiler fuel in 1977 was 300 Mcf or less per day.

III. Boiler Fuel Facilities Not in Existence on November 9, 1978

A. *"In Existence" Term.* The permanent exemption established by section 206(a)(2)(B) for small boiler fuel users applies only to "any industrial boiler fuel facility in existence on the date of the enactment of this Act", *i.e.*, November 9, 1978. Facilities not in existence on November 9, 1978, regardless of size, do not appear eligible for the exemption provided by section 206(a).

Furthermore, section 201 of the NGPA defines an "industrial boiler fuel facility" as one "which uses natural gas as a boiler fuel." Thus, the Commission believes that an industrial boiler fuel facility must have been using natural gas as a boiler fuel on November 9, 1978,

[1] The figures in Table II were made available to the Commission on February 29. EIA requested that it be stated that the data in Table II are subject to further audits and adjustments. Unlike the figures in Table I which are final data, the figures in Table II are preliminary.

or have been capable of doing so, in order to be considered as in existence on that date as an industrial boiler fuel facility. To remove the possibility of ambiguity with respect to this concept,[3] the Commission hereby proposes to amend the incremental pricing program regulations in § 282.202 to include a definition of "in existence on November 9, 1978." The definition set forth below would provide that a facility was in existence as an industrial boiler fuel facility on November 9, 1978, if it (1) was technically capable of burning natural gas as a boiler fuel on November 9, 1978, and (2) is substantially the same facility when it is being reviewed pursuant to this rule as it was during the peak month of usage in 1977.

The primary result of the approach reflected in this definition would be to restrict the class of facilities which can be certified as "in existence on November 9, 1978," and thus potentially eligible for a small boiler facility exemption. The Commission believes that if a major modification of a facility has been undertaken since 1977, the facility should not be viewed as having been in existence on November 9, 1978. The Commission is primarily concerned with respect to facilities that were "small" in 1977, but which may have been substantially enlarged in size since then. These facilities should not now be eligible for a small boiler exemption if that exemption is based on consumption data no longer indicative of the facility's size or natural gas requirements.

B. *Exemption for Other Facilities.* On September 28, 1979, the Commission issued a Notice of Proposed Rulemaking in Docket No. RM79–48 to exempt from the incremental pricing program natural gas used as boiler fuel in small industrial facilities which either came into existence after November 9, 1978, or which may come into existence at some time in the future (44 FR 57783, October 5, 1978).

Because the purpose of the rule proposed in this Notice is to define the scope of the "small existing industrial boiler fuel users" exemption as required by section 206(a) of the NGPA, the Commission will not in this docket attempt to deal with the question of exemptions under section 206(d) for small facilities not otherwise eligible for the section 206(a) exemption. The issue is addressed, however, in a further notice of proposed rulemaking in Docket No. RM79–48, issued concurrently with this Notice, that seeks additional comment on a range of exemptions that would go beyond the scope of the existing small boiler exemption in section 206(a) of the NGPA.

IV. Large Users heavily Curtailed in 1977

On December 27, 1979, the Commission issued Order No. 49–A, the order on rehearing of the final regulations on incremental pricing issued in Docket No. RM79–14 (45 FR 767, January 3, 1980). In that Order the Commission discussed several comments which pointed out the potential inequity associated with the grant of a small user exemption to otherwise large industrial users whose deep curtailments in 1977 caused them to meet the "small" user definition, as measured by the 300 Mcf per day threshold. These "large" users then resumed far greater use of gas as curtailment abated in 1978 and 1979.

The Commission is of the belief that potentially serious inequities may arise if a facility which under normal operations consumes a volume of natural gas as boiler fuel that exceeds the "small" boiler threshold to nonetheless qualify for an exemption as a "small" facility. The Commission also believes that the continued exemption of the natural gas used in such facilities from incremental pricing surcharges will work to the detriment of one of the primary purposes of the incremental pricing program, *i.e.*, the shielding of residential and small commercial users from higher gas costs.

[3] In a petition filed in Docket No. RM79–14 requesting rehearing of Order No. 49, the Natural Gas Pipeline Company of America requested that the Commission clarify this term. Also, Commission staff has received numerous questions on this term over the last few months.

The preliminary view of the Commission, however, is that it lacks the appropriate statutory authorization to find boilers that were "small" in 1977 but "large" today to be non-exempt pursuant to section 206(a). Under section 206(a) a facility is eligible for an exemption if it meets the 1977 base period usage test and the 1978 "in existence" test. The Commission is currently of the view that this does not provide the requisite authority to revoke the statutory exemption apparently provided these boilers by section 206(a). However, the Commission views the issue of its authority to address this problem to be an open question and seeks comments and suggestions on how it should proceed.

Several potential approaches to address the potential inequity resulting from some current large users enjoying an exemption from the incremental pricing program have been considered by the Commission. Among these are:

1. For those facilities which came into existence between January 1, 1978 and November 8, 1979, the statute could be interpreted to require some usage in 1977, *i.e.*, a daily average in the month of peak usage of at least 1 Mcf but no more than 300 Mcf.

2. "Usage" in section 206(a) could be interpreted to mean the greater of: the volume of natural gas actually used in a facility; or the volume that would have been used under normal operating conditions had the facility been in existence and had it not been curtailed.

3. The statute provides for an exemption up to and including an average of 300 Mcf per day. One possible interpretaton of this could be that only the first 300 Mcf per day of usage is exempt, and the volumes consumed by exempt facilities for boiler fuel in excess of the 300 Mcf threshold are subject to incremental pricing surcharges.

4. Section 206(d) of the NGPA might be read so as to give the Commission the authority to take away an exemption by, in effect, proposing to exempt certain categories of facilities from an exemption granted pursuant to another provision of the statute.

The Commission solicits comments on both the seriousness of the issue and on the legal interpretations outlined above, or any other approaches, that it should consider.

V. Effective Date

The regulations proposed herein, if adopted as a final rule, would set the small boiler facility threshold permanently at 300 Mcf per day and would clear up confusion as to the meaning of the term "in existence." The Commission sees no reason for delaying the effective date of these regulations. Therefore, the Commission proposes that this rule would take effect as soon as possible after its issuance as a final rule.

VI. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80–24. An original and 14 copies should be filed. All copies received on or before April 4, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection through the Commission's Office of Congressional and Public Affairs, Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. during regular business hours.

B. *Public Hearings.* Public hearings concerning this proposal will be held in Washington, D.C., on March 28, 1980, beginning at 9:30 a.m. and in Los Angeles, California on April 1, 1980, beginning at 9:00 a.m. The Washington hearing will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The Los Angeles hearing will be held in the Auditorium of the State Building, 107 South Broadway, Los

Angeles, California 90016. The hearings will be held for the purpose of receiving oral comments on three Commission proposals with respect to incremental pricing the above proposal; the proposal issued today in Docket No. RM79-48, *Section 206(d) Exemption for Small Industrial Boiler Fuel Facilities from the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978;* and the interim rule issued December 27, 1979, in Docket No. RM80-16, *Disclosed Estimation Methodology Approach for Determination of Volumes of Natural Gas Used for Exempt Purposes under the Incremental Pricing Program.*

Requests to participate in a hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than March 24, 1980, and should indicate the hearing for which the request is made. Requests should reference Docket No. RM80-24, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in a pulbic hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in each hearing will be available in the Commission's Division of Public Information, Office of Congressional and Public Affairs, three days before the hearing and will be available at the site of the hearing on the morning it is convened.

Members of the hearing panel will be designated by the Chairman of the Commission. The hearings will not be of a judicial or evidentiary type. there will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at each hearing. Transcripts of the hearings will be available through the Commission's Office of Congressional and Public Affairs, Division of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282 of Subchapter I, Title 18, Code of Federal Reguations, as set forth below.

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.202 is amended by the addition of a paragraph (f) to read as follows:

§ 282.202 Definitions.

For the purposes of this subpart:

• • • • •

(f) "In existence on November 9, 1978" means that an industrial boiler fuel facility (1) was using, or had the installed capability to use, natural gas as a boiler fuel on November 9, 1978; and (2) is substantially the same facility when it is being reviewed to determine if it was in existence on November 9, 1978, as it was during the month of peak usage in 1977.

2. Section 282.203(a) is amended to read as follows:

§ 282.203 Exempt end-uses.

(a) In accordance with the provisions of section 206(a), (b), and (c) of the NGPA, natural gas used for the following purposes shall be exempt from incremental pricing under this part:

(1) All gas used for boiler fuel by an industrial facility which was:

(i) In existence on November 9, 1978; and

(ii) Consumed an average of 300 Mcf per day or less for boiler fuel during the month of peak use during calendar year 1977; • • •

• • • • •

¶ 32,059 Permanent Rule Defining Agricultural Uses Exempt from Incremental Pricing Under the Natural Gas Policy Act of 1978 and Rule Exempting Agricultural Uses from Incremental Pricing Surcharges

45 F. R. 15563 (March 11, 1980)

18 CFR Part 282

[Docket No. RM80-28 and RM80-29]

Permanent Rule Defining Agricultural Uses Exempt from Incremental Pricing Under the Natural Gas Policy Act of 1978 and Rule Exempting Agricultural Uses from Incremental Pricing Surcharges

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemakings.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby issues two proposed rules relating to the definition of agricultural uses for purposes of the incremental pricing program established by the Natural Gas Policy Act of 1978 (NGPA). The first proposed rule, in Docket No. RM80-28, would exempt an agricultural use from being incrementally priced only if the Commission should determine there is no economically practicable or reasonably available alternative fuel for the agricultural use. The second proposed rule, in Docket No. RM80-29, would exempt all agricultural uses from application of the alternative fuel test until May 1, 1981. Because of the interrelationship between these two proposed rules, the Commission has instructed that they be published as a single package. Accordingly, both proposals are contained in this documents.

DATES: Requests to participate in the public hearing by March 21, 1980. Hearing date: March 27, 1980, beginning at 1:00 p.m. Comments due: April 4, 1980.

ADDRESSES: Requests to participate and written comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. [Reference Dockets Nos. RM80-28 and RM80-29). Hearing location: Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8079.

SUPPLEMENTARY INFORMATION:

In the matter of permanent rule defining agricultural uses exempt from incremental pricing under the Natural Gas Policy Act of 1978 (Docket No. RM80-28); and Section 206(d) rule exempting agricultural uses from incremental pricing surcharges (Docket No. RM80-29).

Issued: March 6, 1980.

The Federal Energy Regulatory Commission (Commission) hereby issues two proposed rules relating to the definition of agricultural uses for purposes of the incremental pricing program established by the Natural Gas Policy Act of 1978 (NGPA). The first proposed rule, in Docket No. RM80-28, would exempt an agricultural use from being incrementally priced only if the Commission should determine there is no economically practicable or reasonably available alternative fuel for the agricultural use. The second proposed rule, in Docket No. RM80-29, would exempt all agricultural uses from application of the alternative fuel test until May 1, 1981.

The proposal in Docket No. RM80-28 is aimed at meeting the statutory directive of section 206(b)(2) of the NGPA. The companion proposal in Docket No. RM80-29 would provide for a one-year delay in the effectiveness of the rule proposed in Docket No. RM80-28. The combined effect of the two proposals would be to exempt all agricultural uses, as defined in the statute and the Commission's

regulations, from incremental pricing until May of 1981.

Because of the interelationship between these two proposed rules, the Commission has instructed that the two proposals be published as a single package. Accordingly, the proposals in Docket No. RM80-28 and Docket No. RM80-29 are contained in this document.

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

In the matter of permanent rule defining agricultural uses exempt from incremental pricing under the Natural Gas Policy Act of 1978 (Docket No. RM80-28).

Issued: March 6, 1980.

I. INTRODUCTION

Title II of the NGPA requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as boiler fuel in large industrial facilities. Under section 202 of Title II, the Commission may expand the incremental pricing program to industrial uses other than boiler fuel use. Any expansion proposed by the Commission is, pursuant to the statute, subject to Congressional review.

Section 206(b) of the statute sets forth the parameters of an exemption from the incremental pricing program for agricultural uses of natural gas.

Section 206(b) provides as follows:

(b) AGRICULTURAL USES OF NATURAL GAS.—

(1) INTERIM EXEMPTION.—During the period preceding the effective date of any permanent exemption under paragraph (2), the rule prescribed under section 201 shall not apply to any facility to the extent of any agricultural use of natural gas.

(2) EXEMPTION BY RULE.—Not later than 18 months after the date of the enactment of this Act, the Commission shall prescribe and make effective a rule providing for the exemption from the rule required under section 201 (including any amendment under section 202 to such rule) any facility with respect to any agricultural use of natural gas for which the Commission determines that an alternative fuel or feedstock is not—

(A) economically practicable; or

(B) reasonably available.

(3) AGRICULTURAL USE DEFINED.—For purposes of this subsection, the term "agricultural use", when used with respect to natural gas, means the use of natural gas to the extent such use is—

(A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or

(B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

As can be seen from the above, the statute prescribes that the agricultural use exemption is to consist of two distinct phases. In the initial phase, section 206(b)(1) provides that all "agricultural uses," as defined in section 206(b)(3), shall be exempt from incremental pricing surcharges for the duration of the initial phase (characterized in the statute as the "interim exemption").

In the second phase of the agricultural exemption, the statute provides that the Commission shall prescribe a rule to exempt from incremental pricing surcharges those agricultural uses—again utilizing the definition set forth in section 206(b)(3)—for which "the Commission determines that an alternative fuel or feedstock is not—(A) economically practicable; or (B) reasonably available.

The Commission implemented the interim exemption for agricultural uses through provisions in the regulations adopted for Phase I of the incremental pricing program.[1] Specifically, § 282.203(b) of the Commission's regulations provides that "all gas used for an agricultural use" is exempt from incremental pricing surcharges. The definition of "agricultural use" is set forth in § 282.202(a) of the Commission's regulations. This definition incorporates

[1] Order Nos. 49, 50 and 51, issued September 28, 1979 (44 *Fed. Reg.* 57725, October 5, 1979).

by reference the listing of essential agricultural uses as determined by the Secretary of Agriculture and certified to the Commission pursuant to section 401(c) of the NGPA. The definition in § 282.202(a) also includes other agricultural uses of natural gas which come within the bounds of the definition set forth in section 206(b)(3).

Section 206(b)(2) of the NGPA provides that the Commission shall adopt the rule defining the permanent agricultural exemption "not later than 18 months after the date of the enactment of this Act," *i.e.*, May 9, 1980. The proposal set forth here is aimed at meeting that statutory directive.

However, the Commission is issuing concurrently with this Notice a proposal which would serve to delay the effectiveness of the rule contained herein, if adopted as a final rule, for a period of approximately one year. The companion one-year exemption to the proposed alternative fuel test set forth here is being issued in Docket No. RM80–29, and is being proposed pursuant to the authority of section 206(d) of the NGPA.

II. Proposed Amendment

The proposed rule would amend § 282.203 of the Commission's regulations. This section sets forth those uses of natural gas which are exempt from incremental pricing surcharges. The rule proposed hereby would exempt any "agricultural use" within the definition of § 282.202(a) from being incrementally priced only if the Commission should determine there was not an economically practicable or reasonably available alternative fuel or feedstock for natural gas in the subject agricultural use. Stated differently, the proposed rule would define "agricultural use" broadly, and would provide an exemption for a use falling within that broad definition only to the extent that the Commission determined such use should be exempt, based on the alternative fuel capability tests set forth in the statute. The proposed rule would not provide for an alternative fuel or feedstock test; thus, under the rule below, no exemption from incremental pricing would be available for natural gas utilized for an "agricultural use." Recall that only where the Commission makes an affirmative determination that alternative fuel capability *does not* exist does an agricultural use become exempt.

However, the companion proposal in Docket No. RM80–29 would exempt all agricultural uses (as defined in § 282.202(a)) from consideration of the reasonable availability or economic practicability of an alternative fuel or feedstock through April 30, 1981. Thus, all "agricultural uses" now subject to an interim exemption would continue to be exempt from incremental pricing surcharges up until May of 1981. The proposal in Docket No. RM80–29, because it is based on the authority of section 206(d) of the NGPA, must be referred to the Congress for review and will take effect only if not disapproved by either House.

It is the Commission's intention to work on an alternative fuel or feedstock test which would ultimately be included in the rule proposed below and would become effective in May 1981. As discussed in more detail in the companion proposal in Docket No. RM80–29, it is hoped this alternative fuel test can be made consistent with the similar alternative fuel test being developed for purposes of Title IV of the NGPA.

III. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80–28. An original and 14 copies should be filed. All copies received on or before April 4, 1980 will be considered by the Commission prior to promulgation of final regulations. All writen submissions will be placed in the Commission's public files and will be available for public inspection through the Commission's Office of Congressional

and Public Affairs, Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing.* A public hearing concerning this proposal will be held in Washington, D.C. on March 27, 1980, beginning at 1:00 p.m. The hearing will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. The hearing will be held for the purpose of receiving oral comments on the above proposal and its companion proposal issued concurrently in Docket No. RM80–29, *Section 206(d) Rule Exempting Agricultural Uses from Incremental Pricing Surcharges.*

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than March 21, 1980. Requests should reference Docket No. RM80–29, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of those participating in the hearing will be available in the Commission's Division of Public Information, Office of Congressional and Public Affairs, three days before the hearing and will be available at the site of the hearing on the morning it is convened.

Procedural rules for the hearing will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available through the Commission's Office of Congressional and Public Affairs, Division of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

Section 282.203 is amended by revising the introductory paragraph and paragraph (b) to read as follows:

§ 282.203 Exempt end-uses.

Natural gas used for the following purposes shall be exempt from incremental pricing under this part:

* * *

(b) *Agricultural use.* Gas used for an agricultural use shall be exempt from incremental pricing under this part only to the extent that the Commission has determined that there is not an economically practicable or reasonably available alternative fuel or feedstock which may be utilized in the agricultural use.

In the matter of Section 206(d) rule exempting agricultural uses from incremental pricing surcharges (Docket No. RM80–29).

Issued: March 6, 1980.

I. Introduction

Title II of the NGPA requires that natural gas used as boiler fuel in large industrial facilities be incrementally priced. Under section 202 of Title II, the Commission may expand the incremental pricing program to industrial uses other than boiler fuel use. Any expansion proposed by the Commission is, pursuant to the statute, subject to Congressional review.

Section 206(b) of the statute sets forth the parameters of an exemption from the incremental pricing program for agricultural uses of natural gas. The statute prescribes that this exemption is to consist of two phases. In the initial phase, section 206(b) provides that all "agricultural uses," as defined in section 206(b)(3), shall be exempt from incremental pricing surcharges for the duration of the initial phase (characterized in the statute as the "interim" exemption).

In the second phase of the agricultural exemption, the statute provides that the Commission shall prescribe a rule to exempt from incremental pricing surcharges those agricultural uses—again utilizing the definition set forth in section 206(b)(3)—for which "the Commission determines that an

alternative fuel or feedstock is not—(A) economically practicable; or (B) reasonably available."

Section 206(b)(2) of the NGPA provides that the Commission shall adopt the rule defining the permanent exemption "not later than 18 months after the date of the enactment of this Act," or May 9, 1980. The proposal set forth in Docket No. RM80–28 is aimed at meeting this statutory directive.

The proposal set forth below is a companion to that in Docket No. RM80–28. The proposal herein would provide for a one-year delay in the effectiveness of the rule proposed in Docket No. RM80–28. The combined effect of the two proposals would be to exempt all agricultural uses, as defined in the statute and the Commission's regulations, from incremental pricing until May of 1981.

II. Discussion

The rule proposed in Docket No. RM80–28 would provide that an agricultural use of natural gas is exempt from incremental pricing only to the extent that the Commission determines an alternative fuel or feedstock for that agricultural use is not economically practicable or reasonably available.

The rule proposed herein would exempt all agricultural uses from application of an alternative fuel test through April 30, 1981, because it would provide that all agricultural uses (as defined in § 282.202(a)) are exempt from being surcharged for the period through April 30, 1981.

The rule below is a proposed rule upon which the Commission seeks comment. It is proposed pursuant to the provisions of section 206(d) of the NGPA, which states that:

> * * * the Commission may * * * provide for the exemption, in whole or in part, of any other incrementally priced industrial facility or category thereof * * *.

The Commission's determination to utilize the section 206(d) approach stems from its relatively clear grant of authority to prescribe the type of rule proposed in this Notice, and in order to give the Congress an opportunity to react to this rule, given its potential for reducing the scope of the incremental pricing program to less than its statutory design for the period of the effectiveness of the rule.

III. Basis For Proposal

There are four reasons for the proposal set forth here. First, the Commission currently has under consideration a proposal for Phase II of the incremental pricing program (see Notice of Proposed Rulemaking in Docket No. RM80–10, issued November 15, 1979 (44 FR 67170, November 23, 1979)). Under the statute, the Commission must adopt a Phase II rule by May 9, 1980, and send it to the Congress for review. If the Commission should determine to adopt as a final rule in Phase II a significant expansion of the incremental pricing program, the universe of end-users impacted by the program, and thus by any permanent agricultural exemption, will be greatly enlarged. Further, the relevant factors to be considered with respect to the agricultural exemption would be increased, and the complexity of the task encompassed by the test set forth in section 206(b)(2) would be affected. Thus, the Commission believes it may be premature to attempt to develop a rule which must be applicable to all agricultural users until it is established whether the character and number of those users will be altered by an expansion of the applicability of the entire program.

Second, the Commission is hopeful that the alternative fuel test which must be developed for purposes of the incremental pricing program can be made consistent with the alternative fuel test which must be prescribed for purposes of the curtailment program under section 401 of the NGPA. The Commission currently has in place an interim rule which sets forth an alternative fuel test for purposes of the curtailment program. The Commission has indicated, however, that it will re-evaluate that rule following the current heating season. The Commission believes it would greatly aid affected

end-users if the same alternative fuel test could be used for both programs.

Third, the rule proposed here would provide the broadest possible relief from incremental pricing for agricultural users. Consistent with the Commission's attempts to proceed cautiously and responsibly in its efforts to implement Title II, this action would minimize any adverse impacts on agricultural users. Only after the Commission gains more experience with the operation and results of incremental pricing will it be fully equipped to make the difficult decisions as to which agricultural users, if any should no longer be exempt from the program.

Fourth, but hardly insignificant, is the fact that the Commission's resources are presently being taxed to implement other aspects of the incremental pricing program. The Commission believes that affected end-users are also being taxed to a significant degree in their efforts to understand, review, and comment on Commission proposals in the other areas of the incremental pricing program. The alternative fuel test will require substantial devotion of Commission resources and expertise, and the Commission believes a more adequate implementation of that requirement could be completed at a point in the future, when other aspects of the program have been finalized.

IV. Relationship of Proposal to Phase II of Incremental Pricing

The rule proposed hereby, if adopted by the Commission as a final rule and not disapproved by the Congress, would apply to the Phase I incremental pricing program—or boiler fuel use of natural gas—and to any expansion of the Phase I program which might become effective. As noted above, the Commission currently has under consideration a proposal to expand the program to include non-boiler industrial uses of natural gas.

Thus, the proposal below would exempt all boiler fuel uses of natural gas encompassed within § 282.202(a) and all process and feedstock uses included within that definition, should the incremental pricing program be expanded, from being incrementally priced through April 30, 1981.

V. Effective Date

The Commission proposes to make the rule below and its companion in Docket No. RM80–28 effective on a date soon after the period for Congressional review expires. The rule will be submitted for the 30-day Congressional review period on or before the May 9, 1980 statutory deadline stated in section 206(b)(2) of the NGPA.

VI. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80–29. An original and 14 copies should be filed. All copies received on or before April 4, 1980 will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection through the Commission's Office of Congressional and Public Affairs, Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing.* A public hearing concerning this proposal will be held in Washington, D.C. on March 27, 1980, beginning at 1:00 p.m. The hearing will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The hearing will be held for the purpose of receiving oral comments on the above proposal and its companion proposal issued concurrently in Docket No. RM80–28, *Permanent Rule Defining Agricultural Uses Exempt from Incremental Pricing Under the Natural Gas Policy Act of 1978.*

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission,

825 North Capitol Street, N.E., Washington, D.C. 20426, no later than March 21, 1980. Requests should reference Docket No. RM80-29, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of participants in the hearing will be available in the Commission's Division of Public Information, Office of Congressional and Public Affairs, three days before the hearing and will be available at the site of the hearing on the morning it is convened.

Procedural rules for the hearing will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available through the Commission's Office of Congressional and Public Affairs, Division of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et. seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282 of Subchapter I, Chapter I, title 18, Code of Federal Regulations, as set forth below.

Section 282.203 is amended by revising the introductory paragraph and paragraph (b) to read as follows:

§ 282.203 Exempt end-users.

Natural gas used for the following purposes shall be exempt from incremental pricing under this part:

* * * * *

(b) *Agricultural use.* (1) Gas used for an agricultural use shall be exempt from incremental pricing under this part only to the extent that the Commission has determined that there is not an economically practicable or reasonably available alternative fuel or feedstock which may be utilized in the agricultural use.

(2) *Exemption.* For the period through April 30, 1981, all gas used for an agricultural use shall be exempt from incremental pricing under this part.

¶ 32,060 Treatment Under the Incremental Pricing Program of Natural Gas Used as Boiler Fuel to Raise Steam Which Forms a Step in the Manufacturing Process for Fertilizer

45 F. R. 13122 (February 28, 1980).

18 CFR Part 282

[Docket No. RM80-18]

Treatment Under the Incremental Pricing Program of Natural Gas Used as Boiler Fuel To Raise Steam Which Forms a Step in the Manufacturing Process for Fertilizer; Opportunity To Comment on Whether a Rulemaking Proceeding Should be Established

February 21, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Opportunity to Comment on Whether a Rulemaking Proceeding Should be Established.

SUMMARY: This Notice is issued for the purpose of providing further public notice of the annoucement which was contained in Order No. 49–A, issued December 27, 1979, in Docket No. RM79-14 (45 FR 767, 769, January 3, 1980). The Commission hereby requests comments on whether a rulemaking should be initiated with regard to the treatment under the incremental pricing progam of the boiler fuel use of natural gas to raise steam which forms an integral part in the manufacturing process of fertilizer.

DATE: Comments due March 31, 1980.

ADDRESS: All comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. (Reference Docket No. RM80-18).

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 8113, Washington, D.C. 20426, (202) 357-8079.

SUPPLEMENTARY INFORMATION:

I. Background

In Order No. 49–A[1] issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (December 27, 1979 (45 FR 767, January 3, 1980)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with respect to an exemption from incremental pricing for the natural gas used as boiler fuel to raise steam which in turn is used as an integral part of the manufacturing process of fertilizer. Such an exemption was discussed at pages 8-10 of the order (page 769 in the Federal Register).

This Notice is issued for the purpose of providing further public notice of the announcement which was contained in Order No. 49–A.

II. Discussion

Section 206(b) of the NGPA provides that, for the period until May 9, 1980, all natural gas consumed as boiler fuel for an "agricultural use" as defined in section 206 is exempt from incremental pricing surcharges. The definition of "agricultural use" does not include natural gas used as boiler fuel in the production of certain agricultural products, *i.e.*, fertilizer, agricultural chemicals, animal feed, or food. For these products, section 206(b) provides that only the natural gas used as process

[1] Order Granting in Part and Denying in Part Petitions for Rehearing, Reconsideration, Modification or Clarification, Amending Regulations and Denying Motions to Waive Regulations and Accept Late Filed Petitions.

fuel or feedstock shall be considered to be consumed for an "agricultural use."[2]

As noted in Order No. 49–A, letters have been submitted to the Commission on behalf of Nitram, Inc., a manufacturer of ammonium nitrate fertilizer, requesting that the Commission define "process fuel," as it appears in the section 206(b) definition of "agricultural use," to include natural gas used as boiler fuel where the steam raised by the boiler forms an integral step in the process required to manufacture the final product. In addition, the Commission has received a letter from Vertac Chemical Corporation,[3] a manufacturer of agricultural chemicals and fertilizer, in which it is argued that the natural gas used as boiler fuel by the agricultural chemical/fertilizer industry should be exempt from incremental pricing. Vertac alleges that, since a particular facet of the fertilizer industry, ammonia, uses natural gas primarily as process fuel or feedstock (and not as boiler fuel), the rest of the fertilizer industry is placed at a competitive disadvantage when it is subject to being incrementally priced for its use of natural gas as boiler fuel.

III. Comments Requested

The Commission requests comments on all aspects of this Notice. The Commission particularly invites comments on the following issues:

1. Is the Commission legally empowered to define process use to include some boiler fuel uses of natural gas, as requested by Nitram? In considering the question, commenters are asked to consider the statutory definition of boiler fuel use set forth in section 201(c)(2) of the NGPA [4] as well as the definitions of process gas and boiler fuel set out in § 2.78(c)(8) and (9) of the Commission's regulations.[5]

2. Assuming that, for purposes of incremental pricing, the Commission is free to define "process fuel" as requested by Nitram, would that definition be appropriate, or would some other definition be preferable in the context of a generic rulemaking?

3. How does the above-described use of natural gas in boilers (*i.e.*, "to raise steam which is an integral part of the manufacturing process of a product") differ from other, non-exempt boiler fuel uses of natural gas? How many other types of processes would come under this description of boiler fuel?

4. If a rulemaking proceeding is established in this docket, should the Commission proceed by proposing a definition of process use, or by proposing an exemptive rule under authority of section 206(d) of the NGPA to exempt all boiler fuel use of natural gas by the agricultural chemical/

[2] The exemption for natural gas used as process fuel or feedstock would become significant if, under Phase II of the incremental pricing program, the Commission were to expand the scope of incremental pricing to include all industrial uses of natural gas except those specifically exempted by Title II of the NGPA. The Phase II regulations must be adopted by the Commission by May 9, 1980. See Docket No. RM80–10, Notice of Proposed Rulemaking (November 15, 1979) [44 FR 67170, November 23, 1979].

[3] Vertac Chemical Corporation also filed with the Commission on December 11, 1979, Petitions for Interim and Permanent Relief/Exemption from Incremental Pricing Provisions Pursuant to Section 206(d) and Section 502(c) of the NGPA, Docket No. SA80–62 and Docket No. SA80–63, respectively. On January 11, 1980, an order granting interim relief under section 502(c) was issued in Docket No. SA80–63.

[4] Section 201(c)(2) of the NGPA states:

(2) *Boiler fuel use*—The term "boiler fuel use" means the use of any fuel for the generation of steam or electricity.

[5] 18 CFR 2.78(c) provides that, for curtailment purposes, the following terms are defined as follows:

(8) *Process gas.* Is defined as gas use for which alternate fuels are not technically feasible such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition propane and other gaseous fuels shall not be considered alternate fuels.

(9) *Boiler fuel.* Is considered to be natural gas used as a fuel for the generation of steam or electricity, including the utilization of gas turbines for the generation of electricity.

These definitions are reflected in many interstate pipeline tariffs and are applied in numerous Commission orders and Court decisions

fertilizer industry, as requested by Vertac?[6]

5. If a rulemaking proceeding is established in this docket, should the exemption for certain boiler fuel uses be limited to the fertilizer industry, or should it be extended to include the production of agricultural chemicals, animal feed, and food?

6. Assuming that, for purposes of incremental pricing, a definition of process fuel similar to that proposed by Nitram were adopted by the Commission, how many additional facilities, or how much more natural gas would become exempt from incremental pricing, if the definition applied to: (a) only the fertilizer industry? (b) all agricultural chemical facilities?

7. If a revised definition of process fuel were adopted as requested, or if an exemption were granted under section 206(d), would the savings in natural gas costs represented by an exemption from incremental pricing surcharges be passed along to users of fertilizers and agricultural chemicals?

IV. Written comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this Notice. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80-18. An original and 14 copies should be filed. All comments received on or before March 31, 1980, will be considered by the Commission. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

Kenneth F. Plumb,
Secretary.

[6] If an exemptive rule were adopted by the Commission as a final rule, it would, be the terms of section 206(d), have to be submitted to the Congress for its review and possible one-House disapproval prior to becoming effective.

¶ 32,061 Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes

45 F. R. 22053 (April 3, 1980).

18 CFR Part 2

[Docket No. RM80-42]

Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission is proposing to issue a rule permitting a public utility or interstate pipeline making a rate filing under section 205 of the Federal Power Act or under sections 4 or 7 of the Natural Gas Act to use tax normalization to compute the income tax component for its cost of service. If the rate applicant were to make such an election it would be required to use tax normalization for all timing difference transactions except those addressed in prior Commission orders. The proposed rule is not intended to modify existing procedures contained in the Commission's Uniform Systems of Accounts.

DATES: Written comments by June 30, 1980. Public hearings (if warranted) to be announced.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Reference Docket No. RM80-42.

FOR FURTHER INFORMATION CONTACT:

Angela Lancaster, Office of the Chairman, Federal Energy Regulatory Commission, Room 9000, 825 North Capitol Street NE, Washington, D.C. 20426 (202) 357-8333.

Ronald L. Rattey, Office of Regulatory Analysis, Federal Energy Regulatory Commission, Room 3000F, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357-8186.

Jane E. Phillips, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8104B, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357-8033.

Issued March 31, 1980.

I. Introduction

The Federal Energy Regulatory Commission (Commission)[1] is proposing to amend Part 2 of its regulations by adding a new § 2.202 as a substantive rule applicable to both the electric utility and natural gas pipeline industries. The rule would permit tax normalization, or interperiod tax allocation, with respect to all miscellaneous transactions (other than those specifically excluded as discussed below) that create "timing differences" in the recognition of expenses or revenues for ratemaking (or book) and income tax purposes. In addition, the proposed rule codifies existing Commission practice with regard to the related cost of service effects for the rate base adjustments resulting from the treatment of accumulated deferred income tax accounts.

This Commission's predecessor, the Federal Power Commission, on various occasions considered the issue of normalizing the effects of certain transactions for which timing differences exist. Order No. 530-B, Docket Nos. R-424 and R-446, issued July 6, 1976,[2] represents the culmination of the last generic normalization proceeding before the FPC. That processing, *inter alia*, addressed the ratemaking implications of normalization and modified the provisions of the Uniform Systems of Accounts in order to establish accounting procedures necessary to achieve tax normalization. The instant proceeding has been initiated in response to the February 16, 1979 remand of the Order No. 530 series of the United States Court of Appeals for the District of Columbia Circuit in *Public Systems, et al.* v. *FERC*, 606 F.2d 973 (D.C. Cir. 1979), rehearing denied March 30, 1979.

II. Scope of Proposed Regulation

Although the proposed regulation is relatively broad in scope, certain items are expressly excluded from consideration. It appears neither appropriate nor necessary to re-evaluate the accounting or ratemaking treatment of those timing difference transactions for which normalization has been prescribed in prior proceedings. To the extent that the Commission's treatment of any of the excluded items has been challenged before the courts, the Commission has been sustained in the exercise of its expert judgment. See discussion of legal history, Section V, *infra*. Moreover, because these timing difference transactions were not addressed in Order No. 530 or its progeny, they are beyond the scope of the Order No. 530–B remand.

Thus, this rulemaking proceeding *does not* relate to previously established Commission policy concerning normalization of the tax effects associated with the following timing differences:[3]

(1) Differences that result from the use of accelerated depreciation and Class Life Asset Depreciation Range (ADR) tax provisions. (Order No. 404, May 15, 1970; Opinion No. 578, June 3, 1970; and Order No. 504, February 11, 1974.)

(2) Differences that result from the use of accelerated amortization provisions on certified defense and pollution control facilities. (Order Nos. 203, May 29, 1958; 204, May 29, 1958; and 432, April 23, 1971.)

(3) Differences that arise from recognition of extraordinary property losses as a current expense for tax purposes but as a deferred and amortized expense for book purposes. (Order No. 504, February 11, 1974.)

(4) Differences that arise from recognition of research, development, and demonstration expenditures as a current expense for tax purposes but as a deferred and amortized expense for book purposes. (Order Nos. 408, August 26, 1970; 504, February 11, 1974; and 566, June 3, 1977.)

(5) Differences that result from different tax and book reporting of deferred gains or losses from disposition of utility plant. (Order No. 505, February 11, 1974.)

(6) Differences that result from the use of the Asset Guideline Class "Repair Allowance" provision of the Internal Revenue Code of 1954. (Order No. 504, February 11, 1974.)

(7) Differences that result from recognition of purchased gas costs as a current expense for tax purposes but as a deferred expense for book purposes. (Order No. 13, October 18, 1978.)

Another matter which the Commission does not propose to reconsider at this time concerns the accounting provisions established in Order No. 530.[4] The rule currently under advisement may properly be viewed as enunciating a ratemaking rather than an accounting rule. The accounting practices previously set forth have been incorporated in the Commission's Uniform Systems of Accounts and were not directly at issue on judicial review. Moreover, the provisions of the Uniform Systems of Accounts relating to income taxes are designed to accommodate Commission ratemaking practices, whether or not normalization is utilized. Therefore, changes in ratemaking practices that permit normalization would not need to be accompanied by changes in the Uniform Systems of Accounts.

Having thus narrowed the scope of this rulemaking, the Commission is proposing a rule that would generalize the application of normalization to all other (miscellaneous) timing difference transactions. Order No. 530, at 6-7, identified seven examples of miscellaneous timing difference transactions that had not been considered in prior Commission proceedings. While that list contains the major additional items that would qualify for normalization under the current proposal, it should not be construed as exhaustive. In fact, the policy of comprehensive normalization sought to be implemented by this proposal would encompass a wide variety of less significant timing difference transactions.[5] *See* Appendix

C for additional examples of timing differences.

The proposed rule as well as this preamble attempt to define the term "timing differences" in such a way as to eliminate any confusion concerning the Commission's intent to permit normalization of tax effects associated with all transactions that fit within the definition. Also in this preamble, we distinguish "permanent difference transactions," noting that normalization is inapposite in the case of permanent differences.

The Commission contemplates a uniform application of normalization to the timing difference transactions encompassed by this proposal. Toward that end, the proposed rule requires that a company electing normalization for the tax effects of any of the miscellaneous items must normalize the tax effects of all other miscellaneous timing difference transactions. This condition is necessary because normalization of certain transactions may initially increase revenue requirements, while normalization of others may have an initial rate reducing effect. The same principles support normalization in either case, and we cannot countenance a selective use of normalization which fails to recognize both positive and negative effects on rates.

III. Purposes of Proposed Rule

The primary purposes of this rulemaking proceeding can be summarized succinctly as follows:

(a) To develop a policy that equitably balances the Commission's obligations to ensure reasonable rates for ratepayers while maintaining the financial integrity of the electric and natural gas industries that is necessary for continued reliable service. In establishing such ratemaking policies, it is clear that the Commission must consider a variety of factors. *See, e.g., FPC* v. *Memphis Light, Gas & Water Division, et al.*, 411 U.S. 458, 465–66, 474 (1973). It is also apparent that the Commission has been vested with broad discretion to exercise its expertise in such matters. *See, id.* at 466–67.

(b) To further develop and explain the policy considerations, rationale and cost implications underlying normalization. This proposal addresses, among other matters, the probable impacts of normalization on factors such as cash flow, external financing requirements, cost of capital considerations, price squeeze concerns, rate stability, and overall rate levels. The device by which much of this information is set forth and evaluated is a recently completed staff report incorporated as part of this proposal and attached as Appendix A.

(c) To respond to certain criticisms of Order No. 530–B and the related orders which the Court of Appeals for the District of Columbia Circuit noted in *Public Systems, supra.*

(d) To eliminate an ongoing controversy and attendant uncertainty regarding the appropriate treatment of timing difference transactions in Commission rate proceedings by establishing a generic rule sanctioning normalization. Apart from other considerations, the resulting administrative efficiency and clarity should benefit consumers, regulated utilities, and the Commission. Although an industry-wide determination proscribing normalization might similarly avoid case-specific controversies or eliminate confusion, our inquiry into the subject suggests that normalization more appropriately comports with sound regulatory principles and with the public interest.

IV. Explanation of Normalization and Flow-Through Ratemaking Policies

The computation of allowable income taxes is an integral facet of any cost of service determination. In order to enable a jurisdictional electric utility or natural gas pipeline company to recover its prudently incurred costs and have an opportunity to earn a fair return on the capital that it has invested for the benefit of its consumers, the Commission must concomitantly consider the Federal, state and local

taxes which the company will be required to pay on its earnings. Only by allowing the company to recover such taxes from its ratepayers will the company have the opportunity to realize after-tax earnings at a level which has been determined to be just and reasonable.

The issue of interperiod tax allocation is a subset of the broader question of interperiod cost allocation. In the rate setting process, the Commission invariably must address the question of allocating costs between different periods of time. Taxes, like any other cost of doing business, can be recognized in rates currently or they can be recognized earlier or later than the time at which they are actually incurred. In the final analysis, the Commission must determine whether the interperiod allocation of all costs, including taxes, will produce results compatible with statutory standards.

Under the ratemaking policy known as "flow-through," the tax component of a regulated entity's cost of service is computed so as to reflect the incurrence of expenses and the receipt of revenues consistent with the interperiod cost and revenue allocation policies of the Internal Revenue Service (IRS). "Normalization," on the other hand, conforms the cost of service tax allowance with the associated ratemaking treatment of the underlying expenses and revenues.

The distinction between these two approaches becomes clearer by reference to certain disparities between IRS and Commission policies. Both the IRS and the Commission are bound by statute and by policy to consider a variety of public interest issues in the exercise of their respective responsibilities. However, because the concerns governing the actions of this Commission and those of the IRS do not always coincide, the interperiod allocations of costs and revenues may also differ. If the Commission determines that a current utility expense should not be borne entirely or immediately by current ratepayers, the Commission may require a spreading of the expense over some other time period. However, the IRS may permit the company to recognize the total expense and realize an associated tax deduction in the year of incurrence. [7] When taxing and ratemaking policies diverge in such a manner, a "timing difference" arises.

There are four types of transactions that give rise to timing differences:

1. *Expenses* that are recognized for tax filings in periods *prior to* when they are recognized in rates;

2. *Expenses* that are recognized for tax filings in periods *later than* when they are recognized in rates;

3. *Revenues* that are recognized for tax filings in periods *prior to* when they are recognized in rates; and

4. *Revenues* that are recognized for tax filings in periods *later than* when they are recognized in rates.

The first and fourth types reduce tax liability currently and raise it later. The second and third types raise tax liability currently and reduce it later. In order to avoid confusion, the major focus of our discussion will be on the expense types of timing differences.[8]

The alternative policies of flow-through and normalization have both been advanced as methods for determining an appropriate cost of service tax allowance when there are timing differences. Under the flow-through policy, ratepayers are permitted to realize the tax benefits of expenses (lower tax liability) when those expenses are used as tax deductions by a company. In other words, the entire tax benefit arising from the current deductibility of an expense for IRS purposes is immediately flowed through the company's rates (via its tax allowance) to its customers, despite the fact that the company's rates will recover the related expense in some other period.[9]

Normalization, on the other hand, treats taxes on a deferred or prepaid basis depending upon the ratemaking treatment of the associated expenses. Normalization matches the tax effect of an expense with the ratemaking treatment for recovery of that expense. Normalization acknowledges the timing

difference created by divergent IRS and ratemaking treatment of expenses and revenues and establishes a tax allowance that is consistent with the ratemaking treatment of the expenses and revenues. The procedure permits the regulated company to defer certain of its tax deductions for ratemaking purposes until such time as the expenses which produced the deductions are recovered in the company's rates. Conversely, where ratemaking permits the recovery of an expense earlier than the time at which it is deducted for tax purposes (e.g., plant removal costs), the normalized tax allowance reflects the deductibility of the expense in advance of the actual deduction. The result, again, is a matching of the Commission's treatment of taxes with its treatment of the underlying expenses.

While there are a number of expense and revenue items which create timing differences, normalization operates in essentially the same manner for each. In determining the tax component of the cost of service, a deferred tax component equal to the tax effects of timing difference transactions deducted currently for income tax purposes is added to actual taxes payable in that period. Concurrently, deferred taxes associated with timing difference transactions recognized in rates currently but deducted in other periods for income tax purposes are subtracted from actual taxes payable in that period. These two adjustments (which relate only to expense transactions) can be aggregated into a single (net) deferred tax component. Similar adjustments would relate to revenue transactions. The use of such deferred tax debits and credits causes rates to be set at levels approximating what they would be if the interperiod cost and revenue allocation policies of the IRS were conformed to those of the Commission.

In addition, the Commission requires that accumulated deferred taxes be deducted from the company's rate base prior to applying the overall rate of return in the cost of service computation. This companion practice is designed to ensure that the company's stockholders do not earn a return from ratepayers on those assets financed with deferred tax funds.

As discussed above, the proposed regulation sanctions normalization only with respect to timing differences, not permanent differences. In order to comprehend the distinction between timing differences and permanent differences, it is necessary to recognize two fundamental characteristics of individual timing differences: (1) the difference between recognition of a transaction for tax purposes and for ratemaking purposes arises in one time period and reverses direction or "turns around" in one or more other periods; and (2) over the life of the transaction (before and after the reversal) the total amounts recognized for tax purposes and for ratemaking purposes are equal. In contrast, permanent differences are not offset by reversals in other periods. Rather, they arise when a different dollar value (including nonrecognition of the transaction) is placed on a particular expense or revenue transaction by the IRS than by the regulatory commission. The result is that the total expense deduction or revenue addition taken for tax purposes over time differs from that recognized in ratemaking.[10] Because no interperiod cost or revenue allocation problem exists in the case of permanent differences, normalization is inappropraite for those transactions.

A final important concept relating to the issue of timing differences and interperiod tax allocation is that of "continual tax deferral." This is associated with the composite effects over time of a combination of timing differences affecting a company. A "continual tax deferral" arises when, over time, the total tax benefit associated with new timing differences equals or exceeds the total value of the reversals occurring from earlier timing differences.[11] As a result, under a normalization policy, a positive balance of accumulated deferred taxes reflecting the collection of more taxes in rates than have been paid by the company could exist into the foreseeable future.

Continual tax deferrals are often referred to by the misnomer "permanent

tax savings." This term has the connotation that taxes are not only deferred but are also somehow permanently forgiven. This is inaccurate. Regardless of the number of individual timing differences affecting a given utility, each such timing difference will reverse so that, over the life of the transaction, the total amount of the transaction recognized for ratemaking will equal the total amount recognized for tax purposes. Deferred taxes associated with each timing difference are, in fact, recognized when revenues associated with the transaction are recovered, whether or not the reversals of initial timing differences are replaced by new timing differences of the same or larger magnitude. In addition, as discussed previously, some timing differences (such as those associated with plant removal costs) operate in an opposite manner, so that normalization recognizes tax deductions in the cost of service in advance of IRS recognition of those deductions. Reductions to the accumulated deferred tax accounts associated with this type of timing difference offset, at least in part, the deferred taxes arising from other timing differences. Moreover, and perhaps of greater significance, is the fact that there cannot be a permanence in the deferral of taxes unless there is, concomitantly, a permanence in the deferred recovery of the associated costs. As the staff study notes (Appendix A, Section II.C.), with a tax rate of approximately 50 percent, the associated deferred costs are twice as large as the deferred taxes. It is inconsistent to call continually deferred taxes "permanent tax savings" which should be flowed through to ratepayers and at the same time to maintain rates that continually defer the recovery of the much larger associated expenses.

V. History of the Issue and Standards for Implementation of Commission Policy

In *FPC* v. *Hope Natural Gas Company*, 320 U.S. 591 (1944), the Supreme Court held that there are two aspects of the Commission's authority to assure just and reasonable rates:

> 1. "To protect consumers against exploitation * * *"[12]
>
> 2. To promote the financial interests of the natural gas companies (and, by inference, electric utilities) as measured, not only by revenues sufficient to recover operating expenses and capital costs but also by revenues "* * * sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and to attract capital."[13]

In determining the justness and reasonableness of rates, the Commission utilizes its expertise in selecting from a variety of ratemaking approaches. *FPC* v. *Natural Gas Pipeline Company*, 315 U.S. 575, 586 (1942); *Alabama Tennessee Natural Gas Company* v. *FPC*, 359 F.2d 318, 331 (1966). As discussed below, various courts, including the United States Supreme Court, have recognized the Commission's broad discretion to allow either flow-through or normalization of the tax effects of timing differences. We are unaware of any court decision expressly requiring the Commission to adopt either flow-through or normalization on the basis of any particular factor.

When the FPC first allowed normalization of the tax effects of accelerated depreciation, the United States Court of Appeals upheld the Commission, deferring to the Commission's expertise in the area.[14] Shortly thereafter, when the Commission decided to allow a 1.5 percent rate of return on accumulated deferred taxes, an appellate court upheld the Commission's decision and held that the Commission's discretion was not constrained:

> Since these evaluations are in the expert competence of the Commission, we do not disturb the conclusion derived from them.[15]

In the *Alabama-Tennessee* case,[16] a subsequent Commission (in a three-to-two decision) decided to require the use of flow-through with accelerated depreciation instead of permitting normalization as a previous Commission had done. The Commission relied principally on the "tax deferral"/"tax savings" distinction, finding that normalization would produce "tax savings" for a company's composite plant assuming that plant would remain

stable or grow. On appeal, the Commission was affirmed on the basis that there was substantial evidence to support this finding.[17] The appellate court noted that the problem was in a special field that required a regulatory agency's expertise [18] and that the reasonableness of the entire rate structure (not the mechanics used to arrive at the rate structure) was the important issue.[19] Further, the court stated that:

> The Commission must, of course, concern itself with the possibility of having misread the future and with the future's taking a turn without benefit of advice from the Commission. All things change. But we should expect agency policy to be sufficiently flexible to attempt to change with changing times.[20]

A later Commission voted to permit normalization of the tax effects of accelerated depreciation of certain vintage property in *Texas Gas Transmission Corporation*.[21] again reversing the position of a prior Commission. The primary ground for its decision was that "there is little chance with respect to this plant that there will be any permanent tax savings." [22] The United States Court of Appeals for the District of Columbia Circuit reversed the Commission's opinion in *Texas Gas*,[23] and the Commission appealed that reversal to the United States Supreme Court. In *FPC* v. *Memphis Light, Gas & Water Division*, 411 U.S. 458 (1973), the Court reversed and remanded the decision of the District of Columbia Circuit and held that the Federal Power Commission in *Texas Gas* had correctly decided that it had—

> The authority to determine whether on particular facts the abandonment of flow-through by a utility within the parameter of the Tax Reform Act of 1969 would be in the public interest as envisaged by the Natural Gas Act, even though it might increase rates.[24]

On remand, the District of Columbia Circuit noted this Supreme Court finding [25] and, on the merits, affirmed the Commission's approval of normalization of the tax effects of accelerated depreciation in the utility's cost of service.[26]

The 530 Series of Orders

In 1975, the Commission issued Order No. 530. The order dealt with the tax effects of certain timing differences that had not been covered by previous Commission orders or opinions. The order promulgated accounting amendments relating to normalization and announced a general ratemaking policy in favor of normalization. With respect to the timing differences covered by the rulemaking, Order No. 530 contemplated that the normalization issue would be decided in individual rate cases. Although the Commission stated that parties to a rate proceeding should make an appropriate factual showing to sustain their claims or counterclaims, it did not specify the nature of the factual showings required. In support of its normalization policy the Commission cited the need of both natural gas companies and electric utilities to attract captial, and the tendency of normalization to increase cash flow, reduce external financing requirements, contribute to financial stability and improve fixed charge coverages.

On rehearing, the Commission stated that the courts had required it to find a "tax deferral" rather than a "permanent tax savings" before it could allow normalization.[27] Order No. 530–A therefore required that, in each individual rate case, a "tax deferral" rather than a "tax savings" would have to be proved by the utility with respect to a class of items before that class could qualify for normalization.

In Order No. 530–B, the Commission reassessed the issue. It determined that while the courts had typically dealt with the normalization/flow-through question in terms of the Commission's own standard of deferral versus savings, they had never held that this distinction required the Commission to adopt either flow-through or normalization. According to the Commission, the only bar to the adoption of normalization was if the particular transaction would

cause a permanent difference rather than a timing difference. In view of its freedom to choose between competing accounting methods, and based on the record in Docket Nos. R–424 and R–446 and the policy considerations enunciated in both Order Nos. 530 and 530–B, the Commission ultimately adopted a ratemaking policy permitting normalization of the tax effects of all timing differences between the treatment of items for tax and book purposes. The Commission decided that normalization should be allowed even when accumulated deferred tax balances would grow or remain constant. The Commission also continued the policy of deducting accumulated deferred taxes from rate base.

On petition for review of the 530 series of orders to the District of Columbia Circuit,[28] petitioners contended that the Commission failed to provide a reasonable basis for its action and improperly neglected the anticompetitive consequences of its normalization policy. The court concentrated only on Order No. 530–B. The court held that section 19(b) of the Natural Gas Act imposed the "substantial evidence" standard on informal rulemakings, as well as adjudicatory proceedings.[29] It stated that the Commission's order should "include a reasoned opinion detailing those factual elements in the record that underlie the Commission's actions."[30] Noting that Order No. 530–B "rest[ed] on general policy considerations,"[31] the court concluded that the Commission failed to "assess the consequences of its action for the industry" or to "indicate 'fully and carefully' the purposes behind the order."[32]

In its decision the court discussed in detail its view of the areas in which Order No. 530–B failed to meet the appropriate standards:

1. There was no indication of the impact on consumers or utilities of adopting normalization and no statement as to the financial resources at issue.[33]

2. The orders did not specify all of the expenses that would be covered by normalization, giving seven examples instead.

3. Only three of the seven examples were discussed adequately (interest, pension costs, and taxes incurred during construction). The other items received such summary treatment that the court considered the order to contain an "insufficient explanation of the Commission's position for effective review."[34]

4. As to both the items discussed and those that received summary treatment, there was nothing to support the Commission's implicit conclusion that there would be no "tax savings."[35] (The court apparently equated "tax savings" with growing or constant balances in accumulated deferred taxes.)

5. The order failed to explain the goals of the Commission's policy.[36] The only policy goals mentioned by the order would apply to a generic flow-through policy as well as to a normalization policy.

6. No reason or rationale was given for the Commission's decision to decide the price squeeze implications of normalization on a case-by-case basis.

The court remanded Order No. 530–B to the Commission for further action not inconsistent with the court's opinion.

In order to alleviate the uncertainty among presiding law judges and litigants concerning the procedure to be followed in the wake of *Public Systems*, the Commission issued an Order Establishing Interim Procedures in Docket Nos. R–424 and R–446.[37] The Commission stated that the procedures set forth in Order No. 530–B would remain in effect pending further action on the court's remand. There was only one exception to this policy. If the filing utility submitted evidence on the normalization issue, staff and intervenors would be allowed to submit evidence and engage in cross-examination on the issue. Further, the Commission declared that.

Any final decision which requires a refund of amounts otherwise in excess of the just and reasonable rate level shall not require a

refund of that portion of the rate related to interperiod tax allocation. That portion shall continue in effect, subject to refund, pending a final order in these dockets.

The proposed rule reflects the Commission's effort to follow a course that is consistent with legal precedent, including *Public Systems*, as well as with the Commission's own standards for the implementation of ratemaking policy. The Commission has broad discretion in the determination of the appropriate tax treatment for the cost of service of electric utilities and natural gas pipelines. The Commission also possesses the flexibility to employ a procedure, like the informal rulemaking procedure chosen here, that it believes is best suited to effective resolution of the issue of interperiod tax allocation. *See Vermont Yankee Nuclear Power Corporation* v. *Natural Resources Defense Council*, 435 U.S. 519 (1978). Moreover, the Commission has the option of adopting either flow-through or normalization as long as it sufficiently articulates the policy reasons behind the decision and provides support for the factual underpinnings of those policy reasons.

VI. Policy Considerations

Analysis of the Issue

As a general matter, the rationale underlying tax normalization is different from the rationale underlying flow-through. As discussed in an earlier section, this difference between the two policies is most easily seen with an expense that creates a tax deferral.

Under normalization, the tax effect of an expense is recognized in the cost of service in the same time period as the expense itself is recognized in the cost of service. This is the matching principle that is discussed more fully in Section II.A. of the staff study (Appendix A). Taxes are deferred under normalization when the collection of the expense in rates is deferred. The goal of this matching is to achieve equity, or to ensure fairness,[38] by allocating the tax benefit of an expense to the same customers that pay the expense. To do otherwise would permit subsidization of present consumers by future consumers who would be denied the tax benefit associated with the expense at the time that the expense is recovered in their rates.

Underlying the equity argument is the concept of "used and useful" property. Usually, the determination that a piece of equipment or property can be included in rate base rests on whether that equipment is "used and useful" in providing service to existing ratepayers.[39] If current customers are receiving a service from the equipment or property, it is reasonable to require them to pay for the use of this property. The next step is a logical one. If current customers are paying the expenses associated with a given piece of equipment or property, because they are receiving service from it, they also should be receiving the benefits of the tax deductions arising from the associated expenses. Not only is it fair to match the overall use of equipment or property with payment for that use but also it is fair to match the *tax* benefits of expenses for equipment or property with the expenses themselves.

Conversely, if customers are not receiving service from property or equipment because it is not yet "used and useful," the customers should not be charged for the expenses associated with that property or equipment. Since the expenses are incurred currently but cannot be recovered in rates until some time in the future, it is reasonable to withhold from the rate calculation the tax benefit (deduction) associated with those as yet unrecovered expenses. Moreover, the utility must finance the expenses in some manner. By temporarily allowing the utility to realize the current tax benefit, the burden of financing the expenses is lessened. Customers, in effect, provide some of the financing by way of the deferred taxes included in their rates. At the time that the expenses are eventually recovered in rates, the tax benefit of the expenses is also reflected in rates so that the utility "pays back" the tax benefit to the customers at the time the customers are charged the expenses themselves.[40]

The rationale underlying flow-through, on the other hand, is that customers should not be charged more taxes in any one year that the utility actually pays in taxes during that year. The cost of service tax allowance should match the IRS determined tax liability as closely as possible. This is referred to as the "actual taxes paid" doctrine, a theory often invoked to demonstrate that flow-through is cost-based.

The proposed normalization policy is also cost-based but not in the same manner as the flow-through policy. Normalization does not give special treatment to taxes. Under normalization, taxes are allocated over time on a prepayment or deferral basis in a manner similar to other costs. The fact that other costs are not, as a general rule, allocated on an "as paid" basis does not mean that the ratemaking cost of service is not cost-based. Similarly, the fact that normalization does not allocate taxes on an "as paid" basis does not mean that normalization is not cost-based. It simply means that taxes, like other costs, may be more properly chargeable to periods other than the periods during which the taxes are actually paid by the utility. Further, just as one can say that the allowance for other costs properly covers the actual expenditures made by a utility over time and no more, so too can one say that the tax allowance, under normalization, covers actual taxes over time and no more. Since there is no inherent difference between tax expenses and other expenses, the Commission believes that it is inconsistent to treat them differently, as the flow-through policy does. In addition, because flow-through allocates the tax benefits of expenses to different periods from those periods to which the expenses themselves are allocated, there is a resulting mismatch that creates inequitable results.

A flow-through policy would distort the Commission's pricing objectives in instances in which the Commission determines that the related expense should be recovered in a different time period. As discussed earlier, the Commission must decide for cost allocation purposes whether an expense should be recovered in rates in the same period, after, or before it is incurred by the utility. For instance, if the Commission has determined that a reasonable allocation for the recovery of a $100 expense incurred in year 1 is $50 in each of years 2 and 3, then rates in year 1 should be unchanged and rates in years 2 and 3 should be increased by $50. This is essentially what occurs under a normalization poilicy. A flow-through tax policy, however, produces a very different result. Because income received in the form of a tax allowance represents additional taxable revenues, rates under a flow-through policy actually would be reduced in year 1 by $100 and increased by $100 in each of years 2 and 3.[41]

An advantage of normalization is that, other things being equal, revenue swings between time periods are likely to be more moderate than under flow-through. Thus, a Commission policy objective of revenue stability can be furthered with the adoption of normalization. The tendency toward stability is demonstrated by the staff study in its discussion of the single transaction case (Appendix A, Section II.B.). As the prior example demonstrated, flow-through lowers rates during the construction period below the rate level that would be required absent construction—but by more than the amount of the tax benefit itself—and raises rates during the operating life of the plant—but by more than the expense recovery. Normalization, on the other hand, affects rates during the construction period only slightly, if at all.

The Commission must often balance the benefits of short-term rate reductions to consumers against the longer term effects of its policies on costs and reliability of service. As indicated by the staff study (Appendix A, Sections II.B.2. and II.D.), normalization produces beneficial effects on cash flow and on the costs of obtaining financial capital. Normalization tends to improve a utility's internal cash flow when the need is greatest and to decrease it when

the need it less. Generally, a utility using normalization realizes and is allowed to retain the tax benefits of an expense in the year in which the utility incurs the expense. This lessens the impact of the expense on the utility's cash flow. Conversely, when the expense is recognized and collected in rates and the utility has no actual liability, normalization reduces the amount of the expense actually allowed to be collected by reducing rates to reflect the pass-through of the associated tax benefits to consumers.

Using AFUDC interest as an example, this means that when a utility must expend $100 for this expense, normalization provides $50 of deferred tax debits in rates (assuming a 50 percent tax rate) so that the net impact on the utility's cash out-flow is only $50. When a utility is permitted $100 in rates during a given period to reflect AFUDC interest that it has paid in some prior period(s), normalization reduces the tax allowance by $50 in deferred tax credits so that the net impact on the utility's cash in-flow is only $50.

The financial stability resulting from these effects on cash flow should tend to lower the risks associated with utility investments and thus the costs of capital (*see*, Appendix A, Section II.D.). Further, to the extent that investors view frequent trips to the capital markets as a sign of increased risk, utilities that normalize would be viewed as less risky than flow-through utilities since normalizing utilities, other things being equal, would have lower external capital needs. This also tends to explain the observed lower capital costs to utilities using normalization (*see*, Appendix A, Section II.D.). Since all other costs of service are the same, this lower capital cost means that normalization, over the long-term, should tend to lower the cost of serving customers below flow through. The lower capital costs and improved cash flow, over time, should also aid a utility in attracting capital and enable a utility to replace and maintain equipment to prevent service deterioration.

In summary, the Commission has proposed tax normalization for the timing differences covered in this proceeding as a matter of general ratemaking policy because it believes that the broad regulatory goals of equitable treatment of ratepayers and investors, long-term cost minimization consistent with service reliability, and cost-based rates can be achieved most successfully by adopting this tax treatment method. In addition, the Commission has reviewed the results of the staff study to determine the industry-wide implications on rates of its proposed rule.

Implications of staff's rate impact analysis

The results of the attached staff impact analysis are important in a number of respects. In addition to providing some indication of the relative magnitude of the impact that the proposed rule has on rates, the staff study provides useful information on some of the issues underlying normalization that are most controversial. For example, various parties opposing the implementation of normalization express concern (explicitly or implicitly) that "continual tax deferrals" necessarily result in continually higher electric or natural gas rates. The staff study demonstrates that this is not necessarily the case since normalized rates may fall below flow-through rates even in the presence of "continual tax deferrals." (*See*, Appendix A and discussion, *infra*.)

Staff's quantitative evaluation covered the types of timing differences addressed in the proposed regulation that, for the majority of the individual utilities, can be expected to have the largest impacts on rates. They are:

1. Differences that result from recognition of the following items as current expenses for tax purposes and as capitalized and amortized expenses for ratemaking purposes:
   (a) The interest component of the Allowance for Funds Used During Construction (AFUDC);
   (b) Construction-related pensions; and
   (c) Construction-related taxes.

2. Differences that result from the use of different depreciation lives for taxes and ratemaking.

3. Differences that result from recognition of regulatory commission cost as a current expense for tax purposes and as an expense amortized over a number of years for ratemaking.

In addition, the study discusses, but does not attempt to quantify, the impact on rates of applying normalization to "plant removal (or dismantling) costs."[42] The largest impacts arising from this latter item would be for electric utilities with nuclear generating plants and for natural gas pipeline companies with significant offshore facilities. However, with respect to nuclear plants, the appropriate method for decommissioning remains uncertain and the costs associated with the various methods can vary by a factor of ten (*see*, Appendix A, Section III.A.4.). Therefore, any assessment of the effects on rates or normalizing this item would be very speculative.

While there are numerous other items that create timing differences that would qualify for normalization under the proposed rule, they are believed to be relatively insignificant in comparison to the items that were specifically addressed.[43] Nevertheless, the commission is asking responding parties to supply additional estimates of the effects on rates of permitting normalization for any items that the parties believe to cause timing differences. (*See, Comment Procedure*, Section IX, *infra*.)

With respect to the items listed above for which the staff study did quantify impacts, assuming no difference in the cost of capital for flow-through and normalization, the results indicate that electric utility rates, on average, would have risen 3.3 percent and gas pipeline rates 0.2 percent over flow-through rates in 1976[44] had a utility switched from a flow-through policy to a normalization policy. (*See*, Appendix A, Section III.A.3.) For 1980, the maximum impacts are estimated to be about 2.2 percent for electric utilities and 0.1 percent for gas pipelines. These impacts are generally projected to diminish over the next 20 years, with normalized gas pipeline rates falling below flow-through rates during this time span. In the year 2000, normalized rates are projected to be less than flow-through rates in the natural gas pipeline industry and to be a maximum of about 0.9 percent above flow-through rates in the electric utility industry. This differential for electric utilities continues past the year 2000.

The actual dollar impacts (in constant 1980 dollars)[45] of normalization versus flow-through also are set forth in the staff analysis for the base and life depreciation timing differences (items 1 and 2 listed above).[46] In 1976, jurisdictional required revenues for the gas pipeline industry would have been $26 to $32 million higher (depending on the assumed growth rate) under normalization than under flow-through if all pipelines had switched to normalization of the base and life differences. By 1980, the jurisdictional required revenues are estimated to be $18 to $20 million higher under normalization and to be $4 to $6 million higher by 1990. By the year 2000, jurisdictional required revenues for gas pipelines are projected to be $5 to $10 million *less* under normalization than under flow-through. After the year 2000, the trend of lower revenues under normalization increases.

For electric utilities, jurisdictional required revenues would have been $183 to $234 million higher (depending on the growth rates and still in constant 1980 dollars) in 1976 if utilities had switched to normalization from flow-through for the base and life differences. In 1980, the jurisdictional required revenues would be $149 to $183 million higher under normalization than under flow-through, and by the year 2000, normalization rates would be $58 to $148 million higher than flow-through rates. While the highest estimated dollar impact of $234 million in 1976 appears large, as noted earlier it represents only a little over 3 percent differential between normalized and flow-through rates. For the high growth case of 14 percent, the staff analysis projects total (jurisdictional and non-jurisdictional) electric utility

revenues to be $85 billion in 1980, of which approximately 10 percent represents jurisdictional revenues.

These projections should be qualified. The assumptions as to growth rates and capital cost, which are highly dependent on inflation rates, must be taken with an increasing degree of skepticism as the projections are taken further into the future.[47] In addition, the above conclusions do not incorporate the differential between the overall cost of capital for normalized firms and for flow-through firms, even though there is evidence that such a differential exists (*see*, Appendix A, Section II.D.). When the staff analysis considers the effects of a minor cost of capital differential, that is, flow-through firms face slightly higher costs of capital than firms that normalize, use of normalization eventually results in electric utility rates lower than under flow-through. In the low-growth case, with a ten basis point differential, normalized rates would drop below flow-through rates in the year 2005. A 30-basis point or more differential would yield a lower average rate under normalization by the year 1990 for the low-growth case. (*See*, Attachment A, Section III.A.3.)

With respect to the high-growth case for electric utilities, normalized rates would fall below flow-through rates by the year 2000 if a 30-basis point or more differential is assumed. With a 40 to 50-basis point differential in the high-growth case, normalized rates would be lower than flow-through rates by the year 1990. (*See*, Attachment A, Section III.A.3.) Nevertheless, even if the cost of capital differential is ignored and the higher indicated rates for normalization in fact occur through or beyond the year 2000, this would not be a reason *per se* to disallow tax normalization. (*See*, discussion of equity, *supra*.)

The Commission does not believe that the other timing difference items covered by the proposed rule would substantially affect the quantitative results. Taken alone, plant removal cost, which is probably the most significant item that was not quantified, could conceivably lower normalized rates as compared to flow-through rates for electric companies with significant nuclear generation capacity and for natural gas pipelines with offshore facilities. However, on an industry-wide, average price basis, the probable effect is uncertain. Finally, while the overall impact of the other items may be presumed to increase normalized rates as compared to flow-through rates, at least over the short term, the sporadic occurrence of these items mitigates the possibility that these items will have any significant long-term effect on rates.[48]

As we indicated above, staff's statistical results have significance beyond what they indicate will be the impact of the proposed rule on rates. They also show that, under the most plausible future conditions for both gas pipelines and electric utilities, "continual tax deferrals," as defined *supra*, will exist. Whether or not continual tax deferrals exist has been the primary concern of opponents of normalization. Staff's empirical results as well as its analysis of this issue demonstrate that this concern is misdirected and overstated.

First, staff's study shows that, even in the presence of "continual tax deferrals," normalized rates may fall below flow-through rates. This occurs in both the low and high growth cases for natural gas pipelines.[49] The reason for this occurrence is found in the Commission's policy of deducting accumulated deferred taxes from rate base. Over time, as the tax allowance exceeds taxes payable because of deferred taxes, accumulated deferred taxes continue to grow. This, in turn, increases the rate base deduction and lowers the return and tax allowance in the utility's cost of service. For the range of future growth conditions projected in the staff study for the natural gas pipeline industry, the deduction is enough to eventually bring normalized rates below flow-through rates. For the base differences (including the AFUDC interest expense) that the study models, normalized rates fall below flow-through rates in 1990 for both the low and high growth cases. For the life differences, normalized rates drop

below flow-through rates in 1998 under both low and high growth assumptions. Even though the normalized rates are lower, there continue to be tax deferrals. Thus, there is no direct relationship between "continual tax deferrals" and higher rates under normalization than under flow-through.

Second, the staff study explains that as long as there is a "continual tax deferral," there is an associated continual (non-tax) cost that the utility cannot yet recover from its customers ("continual non-tax cost deferral"). Furthermore, this "continual non-tax cost deferral," which is financed by investors, is twice as large as the associated "continual tax deferral" (assuming a tax rate of 50 percent). Thus if consumers are concerned about a "continual tax deferral," investors should be doubly concerned about the associated "continual cost deferral."

Of course, it should be emphasized that for each individual expense transaction, cost recovery initially deferred is later permitted, and similarly, taxes deferred are later recognized as an offset to the tax allowance. From this perspective, there is neither a continual cost deferral nor a continual tax deferral.

The comparison between the deferred taxes and the associated deferred costs is also important with regard to the cash flow effects of normalization. As discussed above, an important conclusion of the staff study is that normalization improves the cash flow situation of utilities. In terms of those non-tax costs that are continually deferred, and assuming a 50 percent tax rate, this means that half of those costs are paid for with the additional cash provided to utilities by deferred taxes. In other words, the net drain on the utility's cash flow of the continual cost deferral is essentially halved by allowing utilities to normalize.

A final point with respect to the "continual tax deferral" concern is that utility profits are not higher as a result of deferred taxes. Even if the tax allowance under normalization exceeds the "actual taxes paid," the rate of return realized by shareholders is not increased above that allowed by the Commission. The deferred taxes work, simply, to reduce the investment that must be made in the utility with debt and equity funds from investors. The deferred taxes that are deducted from rate base are effectively treated as a form of ratepayer investment on which ratepayers are compensated (on a tax-free basis) through reduced rates. (*See*, Appendix A, Section II.B.1.)

Conclusion

In summary, evaluation of the relative merits of the two policies leads the Commission to conclude that the normalization policy better achieves the goals of the Commission. While both policies result in rates that are cost-based, the normalization policy more equitably balances the interests of present and future ratepayers by matching the interperiod allocation of tax benefits to the interperiod recovery of expenses. Normalization also achieves this objective by improving utilities' ability to attract capital and maintain cash flow and thereby to provide adequate service reliability over the long term. Normalization does not permit stockholders to realize rates of return higher than those allowed.

Flow-through, while resulting in lower rates, at least initially, imposes higher capital costs for which consumers will be responsible now and in the future. Flow-through cost allocation procedures also distort the Commission's pricing policies and result in rates that are less stable than under normalization.

For the above-stated policy reasons, and after reviewing the estimated effects on the industries and their customers, the Commission is proposing regulations that would permit utilities to use tax normalization for the timing differences identified in the proposed rule.

VII. Relationship Between Normalization and the Potential for Discriminatory Effects

We turn now to a consideration of the most appropriate way in which to evaluate any potential for discriminatory effects associated with

our proposed normalization rule. The court in *Public Systems, supra*, expressed concern that a disparity between the normalization policies adopted by this Commission vis-a-vis those of state regulatory agencies might subject certain wholesale customers to "price squeezes." The Commission certainly is aware of this possibility and, indeed, it has been acknowledged as a potential area of inquiry.[50] However, for the following reasons we believe that a case-by-case evaluation of price squeeze issues in electric rate cases is the most soundly-conceived administrative practice. Accordingly, the Commission proposes to utilize such an approach in conjunction with the proposed normalization rule.

Price squeeze allegations are *raised* on a case-by-case basis and Section 2.17 of the Commission's regulations provides a mechanism for framing price squeeze issues in individual cases.[51] The Commission is not persuaded that any single ratemaking principle necessarily creates or eliminates the possibility of a price squeeze situation in all cases. The primary elements of a price squeeze—non-cost-justified disparity between relevant wholesale and retail rates and resulting anticompetitive effect—may be shown to exist or not to exist only by reference to all of the circumstances extant in a particular rate proceeding. Moreover, even upon a convincing demonstration that a price squeeze exists, the available remedies may differ depending upon the facts adduced in a given case. In *FPC* v. *Conway Corporation*, 426 U.S. 271, 279–80 (1976), the Supreme Court made clear that fashioning an appropriate remedy for price squeeze requires "an examination of the entire 'factual context in which the proposed wholesale rate will function'." (*Citing Conway Corporation* v. *FPC*, 510 F.2d 1264, 1273 (D.C. Cir. 1975).)

The rate effect of normalization of the transactions encompassed by this proposal is but one factor to be considered in the overall cost of service analysis. As with any other cost of service determination, normalization may have the effect of increasing a company's allowable revenue levels. The pertinent question is whether the resulting overall rate (i.e., the "end result") is unjust, unreasonable, unduly discriminatory or otherwise unlawful;[52] this is necessarily a case-specific assessment.

The table attached to this proposal as Appendix B sets forth the most current information available concerning the practices of state regulatory authorities with respect to normalization. Although state commissions differ considerably in their approaches to normalization, the table indicates that approximately 45 states have permitted normalization with respect to one or more timing difference transactions. Insofar as a particular state follows normalization practices similar to those of this Commission, normalization itself cannot be labelled as a cause of price squeeze.

Furthermore, even in instances where state commissions proscribe the use of normalization, we cannot conclude, as a generic matter, that our rule permitting normalization will occasion any undue disparity between relevant wholesale and retail rates. There are many differences between the principles which this Commission utilizes in setting wholesale rates and those which the various states employ in establishing retail rates. Examples include disparate treatment of rate of return, cost allocation formulae, rate base valuation methods, as well as test year selection and adjustments. It is quite conceivable that such divergent policies would have offsetting rate effects that would minimize or eliminate any rate disparity otherwise created by conflicting state-federal normalization practices.[53]

Based upon our considered opinion that Commission decisions on cost of service issues will often reduce proposed wholesale rates to a level at which price squeeze concerns are substantially diminished, if not eliminated, we recently revised our general procedures for considering price squeeze allegations.[54] Subject to discretionary modification by the presiding administrative law judge in a given case, price squeeze proceedings are now phased so that a determination concerning the otherwise just and reasonable rate level will precede an

examination of price squeeze allegations. Certainly, where a price squeeze is demonstrated, the impact, if any, of normalization must be considered. However, under the phased procedures which have been initiated, normalization will appropriately be examined along with all other cost of service factors in the particular proceeding. If undue discrimination is found to exist and is caused in whole or in part by differing state-federal treatment or normalization, the Commission may consider the denial of normalization as one of the available remedies for reducing or eliminating the undue discrimination. We believe that any other treatment of normalization as it relates to price squeeze would constitute an artificial and unwarranted isolation or normalization as a ratemaking issue unrelated to other cost of service elements.

VIII. Summary of the Proposed Rule

Proposed § 2.202 permits use of the principles of tax normalization for transactions for which there are timing differences between the amounts of expenses or revenues (relating to those transactions) recognized for income tax purposes and the amounts recognized for ratemaking purposes under the Natural Gas Act or the Federal Power Act. However, those transactions for which the Commission or the FPC has previously articulated a policy of tax normalization are excluded from the scope of the rule.

The general rule in paragraph (b) permits an electric utility or a natural gas pipeline to compute its income tax allowance for its cost of service as if the amounts of expenses or revenues recognized for ratemaking purposes were recognized in the same period for income tax purposes. Thus, tax normalization will be permitted in the periods in which the differences in the amounts recognized first arise and in the periods in which they reverse. Because normalization is optional rather than mandatory, utilities that are required by their state commissions to flow-through for accounting or ratemaking may continue the flow-through practice in their wholesale filings. However, the election affords these utilities the option of using tax normalization for wholesale service alone.

Paragraph (b)(2) states what modifications must be made to rate base when a utility elects to use tax normalization. It codifies existing Commission practice with regard to rate base adjustments for accumulated deferred income tax accounts. Such adjustments are companion practices to tax normalization and relate to Accounts 188, 190 and 281–283 of the Uniform System of Accounts for Electric Utilities and Licensees and to Accounts 188, 190, 191 and 281–283 of the Uniform System of Accounts for Natural Gas Companies.

A utility can only make an election in the context of a rate filing. Although a rate applicant cannot be required to make the initial election (and an intervenor may not use tax normalization to challenge rate filings predicated on flow-through), once it makes such an election it must obtain Commission approval before discontinuing use of tax normalization. This condition is stated in paragraph (c) which also requires that an applicant making an election under § 2.202 apply the principle of tax normalization to all transactions covered by that section, i.e., all timing differences other than those addressed in Orders 203, 204, 408, 432, 404, 504, 505, 566 and 13 and Opinion 578.

The rule further provides that if a timing difference arose in a period prior to the effective date of the election, the rate applicant may only recognize the tax effects of timing differences related to the transaction to the extent that deferred taxes applicable to the transaction have previously been provided for or to the extent that an applicant uses a Commission-approved method for switching from flow-through to normalization for particular timing difference transactions. Thus a rate applicant that had previously used flow-through for a transaction would not be permitted to use tax normalization for that transaction if the timing differences associated with the transaction had

already reversed or if no such Commission-approved method was used. However, this prohibition would not prevent the rate applicant from electing tax normalization for all other transactions to which the prohibition did not apply.

The timing differences excluded from the scope of § 2.202 relate to:

(1) Differences that result from the use of accelerated depreciation and Class Life Asset Depreciation Range (ADR) tax provisions of the Internal Revenue Code of 1954;

(2) Differences that result from the use of accelerated amortization provisions on certified defense and pollution control facilities;

(3) Differences that result from recognition of extraordinary property losses as a current expense for income tax purposes but as a deferred and amortized expense for ratemaking purposes;

(4) Differences that arise from recognition of research, development, and demonstration expenditures as a current expense for income tax purposes but as a deferred and amortized expense for ratemaking purposes;

(5) Differences that result from different reporting for income tax purposes and ratemaking purposes of deferred gains or losses from disposition of utility plant;

(6) Differences that result from the use of the Asset Guideline Class "Repair Allowance" provision of the Internal Revenue Code of 1954; and

(7) Differences that result from recognition of purchased gas costs as a current expense for income tax purposes but as a deferred expense for book purposes.

By defining the term "timing differences" in paragraph (d)(2) to exclude those differences which exist, at least in part, because income tax law and the Commission place different dollar values on a transaction (or one does not recognize the transaction), the Commission has also excluded from the tax normalization rule those transactions for which there are "permanent differences."

The Commission's proposed rule on tax normalization will have the force and effect of a substantive rule when issued in final form. It will appear as § 2.202 of a new subpart to Part 2 and will apply to public utilities and interstate pipelines. The proposed rule is not intended to modify existing accounting procedures contained in the Commission's Uniform Systems of Accounts.

IX. Comment Procedure

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80-42. An original and 14 copies should be filed. All comments received prior to 4:30 p.m., E.D.T., June 30, 1980, will be considered by the Commission prior to promulgation of a final order. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

Comments are invited on all aspects of this proposed rule. In addition, comments and data are specifically invited on the following matters:

1. Data are requested from all interested parties on the impact of the proposed rule, including the impact on both consumers and industry.

2. Respondents are particularly invited to comment on the accuracy of the analysis of the impact of the timing difference transactions quantified in the staff study and attached as Appendix A.

3. Parties are requested to provide any available data pertinent to the additional timing difference transactions identified in Appendices A or C but not quantified, as well as identification and impact of any additional timing difference transactions.

4. Parties are further requested to comment on any unique problems that might be encountered in complying with the rule as proposed, any necessary delay in the effective date of a final rule following issuance of that rule in order to assure satisfactory compliance, and any limitations on the manner in which the rule should be applied to timing differences (related to expenses or revenues) that initially arose prior to the election by an applicant to normalize under the rule. (See § 2.202(c)(2).)

5. Comments are also requested on whether the Commission should require only one of the two methods currently used regarding AFUDC, the gross-of-tax method or the net-of-tax method, whether the Commission should follow state commission policy, or whether other considerations should apply. (*See*, Appendix A, Section II.E.1.)

Upon review of the comments, the Commission will consider whether public hearings are warranted.

(Federal Power Act, 16 U.S.C. § 792, *et seq.*; Natural Gas Act, 15 U.S.C. § 717, *et seq.*; Department of Energy Organization Act, 42 U.S.C. § 7101, *et seq.*; Administrative Procedure Act, 5 U.S.C. § 553, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 2 of Chapter I, Title 18, Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 2—GENERAL POLICY AND INTERPRETATIONS

1. Part 2 is amended in the table of contents and at the end of the text of the regulations in Part 2 by adding a new Subpart to read as follows:

Rules of General Applicability

§ 2.202 Tax normalization for public utilities and interstate pipelines.

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, this section applies to treatment for ratemaking purposes of all transactions for which there are timing differences.

(2) This section does not apply to timing differences addressed by the following orders and opinion:

(i) Order Nos. 203, 204 and 432 (relating to accelerated amortization of certified defense and pollution control facilities);

(ii) Order No. 404 and Opinion No. 578 (relating to accelerated methods of depreciation);

(iii) Order Nos. 408 and 566 (relating to research, development and demonstation expenses);

(iv) Order No. 504 (relating to accelerated methods of depreciation; research, development and demonstration expenses; extraordinary property losses; and use of the Asset Guideline Class "Repair Allowance" provision of the Internal Revenue Code of 1954);

(v) Order No. 505 (relating to deferred gains and losses from disposition of utility plant); and

(vi) Order No. 13 (relating to deferred gas costs under purchased gas adjustment clauses).

(b) *General rule.* (1) A rate applicant may elect to compute the income tax component of its cost of service by using tax normalization for all transactions to which this section applies.

(2) If a rate applicant makes an election under this section, its rate base shall be reduced by the balances for those items related to rate base that are properly recordable in Account 281, "Accumulated deferred income taxes-accelerated amortization property;" Account 282, "Accumulated deferred income taxes-other property;" and Account 283, "Accumulated deferred income taxes-other." Balances for those items related to rate base that are properly recordable in Account 190, "Accumulated deferred income taxes," shall be treated as an addition to rate base. If an applicant uses an approved purchased gas adjustment clause or a research, development and demonstration tracking clause, the rate base reductions or additions required under this subparagraph shall apply only to the extent that the balances in Account 190 and Accounts 281 through 283 are not used, for purposes of

calculating carrying charges, as an offset to balances properly recordable in Account 188, "Research development and demonstration expenditures," or Account 191, "Unrecovered purchased gas costs."

(c) *Conditions.* (1) Except as provided in paragraph (c)(2) of this section, a rate applicant making an election under this section shall be required to use tax normalization for all transactions to which this section applies.

(2) No recognition shall be given to the reverse tax effects of timing differences arising in a time period prior to such election unless:

(i) the applicant has previously provided for applicable deferred taxes: or

(ii) the applicant has adopted a Commission-approved ratemaking method of providing for such deferred taxes.

(3) A rate applicant making an election under this section shall be required to make such election for all future rate filings unless, upon application, the Commission orders otherwise.

(d) *Definitions.*

(1) "Tax normalization" means computing the income tax component as if the amounts of expenses or revenues recognized in each period for ratemaking purposes were also recognized in the same amount in each such period for income tax purposes.

(2) "Timing differences" means differences between amounts of expenses or revenues recognized for income tax purposes and amounts of expenses or revenues recognized for ratemaking purposes, which differences arise in one time period and reverse in one or more other time periods so that the total amounts of expenses or revenues recognized for income tax purposes and for ratemaking purposes in all of such periods are equal.

(3) "Income tax purposes" means for the purpose of computing income tax under the provisions of the Internal Revenue Code of 1954 or the income tax provisions of the laws of a State or political subdivision of a State (including franchise taxes).

(4) "Income tax component" means that part of the cost of service that covers income tax expenses allowable by the Commission.

(5) "Ratemaking purposes" means for the purpose of fixing, modifying, approving, disapproving or rejecting rates under the Federal Power Act or the Natural Gas Act.

(6) "Rate applicant" means a public utility or interstate pipeline that makes a rate filing under section 205 of the Federal Power Act or under sections 4 or 7 of the Natural Gas Act. Interstate pipeline means a natural gas company engaged in natural gas transportation subject to the jurisdiction of the Commission under the Natural Gas Act.

(7) "Transaction" means an activity or event that gives rise to an accounting entry that is used in determining revenues or expenses.

—Footnotes—

[1] The term "Commission" refers to the Federal Power Commission (FPC) with respect to actions taken prior to October 1, 1977, and to the Federal Energy Regulatory Commission with respect to any actions on or after that date.

[2] See *also*, Order Nos. 530 and 530-A, issued June 18, 1975, and January 19, 1976, respectively; Order Denying Rehearing of Order No. 530-B, issued September 3, 1976.

[3] With the exception of item number seven, each of these timing difference transactions was specifically eliminated from consideration in Order No. 530, at 5-6.

[4] These provisions were adopted consistent with accounting practices described in Opinion No. 11 of the Accounting Principles Board of the American Institute of Certified Public Accountants, issued December 1967.

[5] As noted in the Staff analysis that accompanies this proposal (Appendix A), certain of these additional transactions may significantly affect individual companies at particular points in time, although it is unlikely that they would substantially affect industry-wide electric or gas prices.

[6] Unless otherwise indicated, "utility" or "company" refer to both natural gas pipelines and public utilities.

[7] A simple example of this situation is the recovery of regulatory commission expenses. Although these costs are deducted for tax purposes in the year of disbursement, the Commission often requires an amortization of regulatory expenses in order to more nearly establish a representative level for rate purposes. The reverse situation is illustrated

with the example of plant removal costs for which the Commission allows recovery over a period of time prior to actual incurrence and deduction for tax purposes.

[8] Repetitive explanations can be avoided since revenues can be viewed as negatives of expenses, and the analysis of revenue transactions parallels that of expense transactions. Furthermore, expense transactions are the most prevalent types of transactions addressed by the policies and potentially have the most significant effects on rates.

[9] As discussed in Section VI, *infra*, the actual result of the flow-through policy is to reduce the income tax allowance and rates by an amount greater than the tax effect of a deducted expense.

[10] As discussed in Appendix A, Section II.A., examples of permanent differences include municipal bond interest and political contributions.

[11] This relates to timing differences arising from expenses that are recognized as tax deductions prior to their collection in rates. For logical completeness there should also be a term, such as "continual tax prepayments," to relate to expenses recognized as tax deductions after they are recovered in rates.

[12] 320 U.S. at 610.

[13] *Id.* at 603.

[14] *City of Lexington, Ky., et al.* v. *FPC*, 295 F.2d 109, 114 (4th Cir. 1961).

[15] *Panhandle Eastern Pipeline Company* v. *FPC*, 316 F.2d 659, 663 (D.C. Cir. 1962).

[16] Opinion No. 417, 31 FPC 208 (Feb. 3, 1964); Opinion No. 417, 31 FPC 928 (April 15, 1964).

[17] *Alabama Tennessee Natural Gas Company* v. *FPC*, 359 F.2d 318 (5th Cir. 1966).

[18] *Id.* at 330.

[19] *Id.* at 331.

[20] *Id.* at 339.

[21] Opinion No. 578, 43 FPC 824 (June 3, 1970); Opinion No. 578–A, 44 FPC 140 (July 21, 1970).

[22] 43 FPC at 829.

[23] *Memphis Light, Gas & Water Division* v. *FPC*, 462 F. 2d 853 (1972).

[24] 411 U.S. at 472–73.

[25] *Memphis Light, Gas & Water Division* v. *FPC*, 500 F. 2d 798, 807 (1974).

[26] *Id.*

[27] Order No. 530–A, Order Denying Applications for Rehearing and Clarifying Prior Orders, issued January 19, 1976.

[28] *Public Systems, et al.* v. *FERC*, 606 F.2d 97[illegible] (D.C. Cir. 1979).

[29] There is presently a conflict between the United States Circuit Courts of Appeal over the specific question of whether the "substantial evidence" test or the "arbitrary and capricious" standard applies to judicial review of rulemakings under the Natural Gas Act. *Compare Superior Oil Company* v. *FPC*, 563 F.2d 191 (5th Cir. 1977) with *Public Systems, et al.* v. *FERC*, 606 F.2d at 973. The dissent in *Public Systems* argued that the substantial evidence standard should not apply to informal rulemaking. The dissenting Judge would have applied the "arbitrary, capricious, [or] abuse of discretion" standard of the Administrative Procedures Act and would have upheld Order No. 530–B. (606 F.2d at 983, Judge Robb dissenting.) However, several courts have indicated that the "arbitrary and capricious" test and the "substantial evidence" test may not, in practical effect, impose a different standard of review for informal rulemakings. *See ECEE* v. *FERC*, No. 79–1171, —— F.2d —— (5th Cir. February 7, 1980, Slip op. at 3019–20, n. 22); *American Public Gas Association* v. *FPC* 567 F.2d 1016, 1028–29 (D.C. Cir. 1977); *Associated Indus. of N.Y. State, Inc.* v. *U.S. Department of Labor*, 487 F.2d 342, 349–50 (2d Cir. 1973).

[30] 606 F.2d at 979.

[31] *Id.* at 980.

[32] *Id.*

[33] *Id.* at 980–81.

[34] *Id.* at 981.

[35] *Id.*

[36] *Id.*

[37] Issued June 8, 1979.

[38] A finding that rates are fair necessitates a proper balancing of the relative claims of the interested parties in a rate proceeding. The determination of fair or equitable rates must be, by its very nature, within the judgment and discretion of the Commission. The courts have recognized the Commission's "recourse to equitable concepts in striving for the reasonableness that broadly identifies the ambit of sound discretion." *City of Chicago* v. *FPC*, 385 F.2d 629, 642 (1967), and the fact that "conceptions of equity . . . may properly be invoked by administrative agencies seeking to achieve 'the necessities of control in an increasingly complex society without sacrifice of fundamental principles of fairness and justice.'" *Id.* at 642–43, *citing Niagara Mohawk Power Corporation* v. *FPC*, 379 F.2d 153, 160 (1967).

[39] The "used and useful" concept is consistent with the Commission's disallowance of construction work in progress (CWIP) in rate base. Nevertheless, in late 1974, when the Commission proposed a rulemaking to include CWIP in rate base because of the severe financial pressure facing the electric utility industry and the extensive construction programs in progress, the Commission, in effect, was proposing to put aside the matching and equity principles. As financial circumstances eased somewhat, the Commission reiterated its policy of AFUDC capitalization rather than inclusion of CWIP in rate base. However, exceptions were made for pollution control and fuel conversion facilities since the incentive given utilities by CWIP inclusion to pursue pollution control and fuel conversion were necessary to meet national goals of greater importance than the regulatory matching and equity principles enunciated here.

[40] An analogy can be drawn between this result and an involuntary "loan" provided by customers to the utility in the form of deferred taxes. Customers are compensated for the "loan" in the form of reduced rates resulting from rate base deduction of accumulated deferred taxes. This analogy is discussed in Appendix A, Section II.B.1.

[41] For a more complete explanation of this result, see Appendix A, Section II.B.1.

[42] This item is a different type of expense item than the interest portion of AFUDC and is prepaid rather than deferred. Tax normalization would at least initially lower rates below flow-through rates

for this type of timing difference. (*See*, Appendix A, Section III.A.4.)

[43] Other items not addressed also tend to be of differing magnitudes between firms and overtime. Additional items are listed in Appendix C. The Commission believes that the definition of timing differences in the proposed rule is specific enough so that parties to rate proceedings can readily identify those revenue and expense items that create timing differences for which tax normalization would be permitted. Accordingly, it is unnecessary to specify every single revenue and expense item that might give rise to a timing difference.

[44] The year 1976 was the first year during which utilities had the option of adopting normalization for these items.

[45] The 1980 constant dollar base is derived from data for 1976 inflated by the assumed inflation rates used in the individual cases.

[46] *See*, Appendix A, Section III.A.3. and 4. for a more detailed discussion of the base and life difference dollar impacts for the two industries.

[47] The growth rates set forth in the staff study represent current estimates, and, for the past several years, the estimates of future growth rates in the electric power business have been declining. There is every expectation that, to the extent the estimates are revised over the next few years, these revisions are likely to be in a downward direction. In addition, there is a growing practice on the part of electric utilities of sharing the cost of bulk power supply facilities (such as generating units, parts of generating units or specific transmission facilities) with non-jurisdictional systems previously served at wholesale for resale. To the extent this trend continues, the rate of growth in plant investment of jurisdictional electric utilities will be further reduced. Finally, the cogeneration and small power production program set forth in Sections 201 and 210 of the Public Utility Regulatory Policies Act (PURPA) contains provisions designed to encourage investment in generating facilities by non-jurisdictional entities in lieu of generation by jurisdictional electric utilities. This should have a further depressing effect on the growth rate of plant investment by jurisdictional electric utilities.

[48] In this regard we note that the court in *Public Systems* recognized that "precise quantification of all elements of proposed Commission action is not required." (606 F.2d at 981.)

[49] This is also true for electric utilities, assuming a relatively small cost of capital differential. For an expanded discussion of the quantitative results for electric utilities, *see*, Appendix A, Section III.A.3.

[50] *See, e.g.*, Order Denying Rehearing of Order No. 530-B, issued September 3, 1976, at 3.

[51] The Commission's Notice of Proposed Rulemaking in Docket No. RM79-79, issued November 19, 1979, would revise the procedures for consideration of the price squeeze issue in each case in which it is alleged.

[52] *See, FPC* v. *Hope Natural Gas Company*, 320 U.S. 491, 602 (1944) (emphasizing the importance of focusing on the "end result" of various rate determinations).

[53] For instance, any short term rate-inflating effect that may be ascribed to normalization might be offset, in whole or in part, if this Commission were to authorize a lower rate of return than that allowed in a particular state. The same result might occur with respect to our use of original cost in valuing a company's rate base, as contrasted with the use of reproduction cost or fair value by the state in which a jurisdictional company operates.

[54] *See, e.g., Arkansas Power & Light Company*, Docket No. ER79-339, Order issued August 6, 1979, at 6. *See, also, Price Squeeze-Procedural Rules*, Docket No. RM79-79, Notice of Proposed Rulemaking, issued November 19, 1979.

¶ 32,062 Definition of Agricultural Use in § 282.202(a) of the Commission's Regulations on Incremental Pricing

45 F. R. 25825 (April 16, 1980)

18 CFR Part 282

[Docket No. RM 80-48]

Definition of Agricultural Use in § 282.202(a) of the Commission's Regulations on Incremental Pricing; Proposed Rulemaking

April 10, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby issues a proposed rulemaking to expand the scope of agricultural uses of natural gas defined in § 282.202(a) of the Commission's regulations on incremental pricing. The Commission proposes herein to amend § 282.202(a) to include the processing or manufacture of: the food preservative BHA; food-grade microcrystalline and synthetic paraffin waxes; hardboard, tempered and untempered (SIC Code 24996); cellulosic man-made fibers (SIC Code 2823); and cotton linters (SIC Code 2899).

DATES: Requests to participate by May 27, 1980. Hearing date: June 3, 1980. Comments due: May 23, 1980.

ADDRESSES: Requests to participate and written comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Hearing location: Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE. Washington, D.C. 20426, (202) 357-8079.

I. Background

On September 28, 1979 (44 FR 57726, October 5, 1979), the Federal Energy Regulatory Commission (Commission) issued final regulations in Docket No. RM79-14 (Order No. 49) and Docket No. RM79-21 (Orders Nos. 50 and 51) to implement the first phase of the incremental pricing program under the Natural Gas Policy Act of 1978 (NGPA).

Section 206(b) of the NGPA requires that the Commission provide an interim exemption from the incremental pricing program for an industrial facility "to the extent of any agricultural use of natural gas" by that facility.[1]

The definition of "agricultural use" proposed by the Commission in the Notice of Proposed Rulemaking which was the basis for Order No. 49 (June 5, 1979 (44 FR 33099, June 8, 1979)), was limited to those uses of natural gas certified by the Secretary of Agriculture in 7 CFR 2900.3 as "essential agricultural uses" pursuant to section 401(c) of the NGPA.[2]

[1] An interim exemption for agricultural uses is to remain effective until such time as the statutorily required "permanent exemption" for agricultural uses becomes effective. See Notice of Proposed Rulemakings issued March 6, 1980 (45 FR 15563, March 11, 1980), in Docket No. RM80-28, *Permanent Rule Defining Agricultural Uses Exempt from Incremental Pricing Under the Natural Gas Policy Act of 1978*; and Docket No. RM80-29, *Rule Exempting Agricultural Uses from Incremental Pricing Surchanges.*

[2] For a discussion of "essential agricultural use" as defined in section 401(c) and "agricultural use" as defined in section 206(b), see Order No. 49, Docket No. RM 79-14, 44 FR at 57732-57733.

The American Textile Manufacturer's Institute (ATMI) filed comments on the June 5th proposal in which they argued that the use of natural gas as boiler fuel in textile manufacturing operations should be considered an agricultural use, since the manufacture of textiles (insofar as natural fibers is involved) is "natural fiber processing."[3]

In response to ATMI's comments, the Commission, in Order No. 49, promulgated a definition of agricultural use which included—in addition to those Standard Industrial Classification (SIC) Codes certified by the Secretary of Agriculture in 7 CFR 2900.3—the SIC Codes which represent the processing and finishing of natural fiber by the textile industry into a usable form.

In the Commission's order on rehearing in Docket No. RM79-14, Order No. 49-A (December 27, 1979 (45 FR 767, January 3, 1980)), the definition of agricultural use in § 282.202(a) was revised by the addition of SIC Codes representing the plywood and paper industries. The revisions were made in response to petitions filed requesting rehearing of Order No. 49.

Subsequent to the issuance of Order No. 49-A, additional petitions have been submitted to the Commission on behalf of industries which it is argued meet the definition of "agricultural use" in section 206(b) of the NGPA. Two of the requests were in the form of petitions for rehearing of Order No. 49-A.[4] The remaining requests were in the form of requests for interpretations and adjustments.[5]

The Commission, in its denial of rehearing of Order No. 49-A, issued February 21, 1980, stated that the opening of a new docket would be the most efficient and appropriate method for handling the petitions received to date with respect to which SIC Codes should be included in § 282.202(a) and with respect to which fibers should be considered "natural fibers." This Notice is the notice referred to in the Order Denying Rehearing. By opening a separate docket to address the question of the scope of § 282.202(a), the Commission will be able to receive all comments on this question before final disposition of the matter and to determine in a consistent and equitable manner what additional categories, if any, should be included in the definition of agricultural use. (Under the Commission's proposed action in Dockets Nos. RM80-28 and RM80-29, these categories would be exempt from the incremental pricing regulations through at least April of 1981.)

II. Discussion

Following is a brief description of the categories for which the Commission has thus far received petitions requesting their inclusion within the definition of agricultural use in § 282.202(a).

A. *SIC Code 24996 Hardboard, tempered and untempered.* The American Hardboard Association argues that, because the Commission has determined that wood is a natural fiber, and because hardboard is "a panel manufactured primarily from inter-felted lignocellulosic fiber (usually wood)," the manufacture of hardboard is "natural fiber processing."

B. *SIC Code 2823 Cellulosic Man-Made Fibers.* Man-Made Fiber Producers Association (Man-Made

[3] Section 206(b)(3) of the NGPA defines agricultural use as follows:

(3) *Agricultural use defined*—For purposes of this subsection, the term "agricultural use", when used with respect to natural gas, means the use of natural gas to the extent such use is—

(A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or

(B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

[4] Petitions for Rehearing were filed by Man-Made Fiber Producers Association and American Hardboard Association.

[5] Requests for interpretations have been filed by Petrolite Corporation, Bareco Division; Universal Oil Products Company, Process Division; and National Steel Corporation, Great Lakes Steel Division. A request for an adjustment/interpretation has been filed on behalf of Knowlton Brothers, Southern Cellulose Division.

Fibers) describes cellulosic man-made fibers such as rayon, acetate, and triacetate as fibers that are produced from dissolving pulp (cellulose), which is a fibrous substance derived from wood. Thus, it is argued, the production of such fibers into a form suitable for further manufacturing is "natural fiber processing."

C. *Processing of rayon, acetate, and triacetate fibers.* Man-Made Fibers also requests that the Commission determine that the downstream processing by textile mills of man-made fibers derived from wood (rayon, acetate, and triacetate) is "natural fiber processing."

D. *Food-grade microcrystalline and synthetic paraffin waxes.* The Bareco Division of Petrolite Corporation requests an interpretation by the Commission to the effect that Bareco's boiler fuel use of natural gas to manufacture food-grade waxes used, for example, as a necessary coating for packaging materials used to package meat, poultry, and frozen foods, and as a protective coating for cheeses is an agricultural use. The manufacture of food related packaging materials and the coating and glazing of these products with food-grade microcrystalline and synthetic paraffin waxes are considered agricultural uses by the Department of Agriculture (USDA) for reasons of food quality maintenance. Thus, Petrolite argues, it is inconsistent and inequitable if the manufacture of the waxes, which are an indispensable link in the food quality maintenance chain, is not also considered an agricultural use.

E. *Food preservative BHA.* The Process Division of Universal Oil Products Company (UOP) requests the Commission to issue an interpretation stating that the manufacture of butylated hydroxyanisole (BHA), a food preservative, qualifies as an agricultural use of natural gas. UOP argues that the manufacture of BHA is an agricultural use because food preservatives are a necessary link in the food quality maintenance chain.

F. *Production of steel used in the manufacture of metal food cans.* The Great Lakes Steel Division of National Steel Corporation has requested an interpretation that, because the manufacture of metal food cans from tinplate is considered an agricultural use of natural gas by USDA, the consumption of natural gas in the production of the steel which is processed into tinplate for use in manufacturing the cans also should qualify as an agricultural use.

G. *Processing of cotton linters (SIC Code 2899 Chemicals and Chemical Preparations, Not Elsewhere Classified).* A petition for an adjustment or interpretation filed on behalf of the Southern Cellulose Division of Knowlton Brothers contains a request that the Commission determine that the boiler fuel use of natural gas to process cotton linters, which are the raw fibers adhering to cottonseed after the cotton ginning operation has removed the staple cotton, is a use of natural gas for "natural fiber processing." It is alleged in the petition that all other phases of the processing of cotton, except the processing of cotton linters, are considered agricultural uses.

III. Commission Proposal

The Commission believes that the manufacture of hardboard (SIC 24996 Hardboard, tempered and untempered), the production of cellulosic man-made fibers (SIC Code 2823), and the processing of cotton linters (SIC Code 2899 Chemicals and Chemical Preparations, Not Elsewhere Classified) should be included in § 282.202(a) because it appears the above categories involve natural fiber processing and thus meet the definition of agricultural use set forth in section 206(b) of the NGPA.

The Commission is also inclined to determine that the manufacture of food-grade microcrystalline and synthetic paraffin waxes and the manufacture of the food preservative BHA are agricultural uses because their manufacture appears to be necessary for food quality maintenance.

The Commission believes, however, that the downstream processing by textile mills of cellulosic man-made fibers such as rayon, acetate, and

triacetate is not natural fiber processing but instead is the processing of synthetic, man-made fibers and thus should not qualify for an agricultural use exemption.

Furthermore, the Commission is of the preliminary opinion that the production of steel which is processed into tinplate for use in the manufacture of food cans is not an agricultural use as defined in section 206(b)(3) of the NGPA. Food packaging industries are included in the Secretary of Agriculture's list of essential agricultural uses because of their close and vital connection to food processing.[6] The Commission is inclined to agree with the Secretary of Agriculture's determination not to include the production of steel within the definition of essential agricultural uses because it is not a primary input into the food chain system.[7] However, the Commission does seek comments on this issue, since it has been the subject of extensive informal discussion in the course of the development of the incremental pricing regulations.

Accordingly, the Commission hereby proposes to amend § 282.202(a) to include the above-described categories with the exception of the processing of rayon, acetate, and triacetate fibers and the production of steel. Comments are also requested as to whether there are additional categories of use which should be included in § 282.202(a).

IV. Additional Matter

The amendment proposed herein, if adopted as a final rule, would only grant an exemption to the subject uses of natural gas until such time as the permanent exemption rule pursuant to the requirement of section 206(b)(2) of the NGPA becomes effective. At that time all exemptions encompassed by § 282.202(a) will become subject to the provisions of the permanent rule.

V. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this notice. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80-48. An original and 14 copies should be filed. All comments received on or before May 23, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing.* A public hearing concerning this proposal will be held in Washington, D.C. on June 3, 1980, beginning at 10:00 a.m. at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than May 27, 1980. Requests should reference Docket No. RM80-48 and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of participants in the hearing will be available in the Commission's Division

[6] Department of Agriculture's Interim Final Rule, *Part 2900—Essential Agricultural Uses and Volumetric Requirements—Natural Gas Policy Act*, 44 FR 11518, 11522 (March 1, 1979).

[7] See 44 FR at 11520, 11522.

of Public Information, Office of Congressional and Public Affairs, three days before the hearing and will be available at the site of the hearing on the morning it is convened.

Members of the hearing panel will be designated by the Chairman of the Commission. The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available through the Commission's Division of Public Information, Office of Congressional and Public Affairs.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. 301, *et seq*)

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

¶ 32,063 Advance Payments Under the Natural Gas Policy Act of 1978

45 F. R. 28345 (April 28, 1980); 45 F. R. 35348 (May 27, 1980)

18 CFR 270 and 271

[Docket No. RM80-52]

Advance Payments Under the Natural Gas Policy Act of 1978; Proposed Rulemaking

AGENCY: The Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it proposes to adopt regulations which will define the term "advance payment" and which will impute an interest rate to advance payments made to natural gas producers on or after the date of issuance of this notice. This rule will apply to first sales of natural gas not subject to § 271.403 of regulations (renumbered as § 270.207(a) in this proposed rule). The proposed interest rate will be equal to the average prime rate for each calendar quarter. The rate shall be compounded quarterly and shall be computed from the date upon which the advance payment was accepted. The proposed rule further requires that the producer not receive more than half the applicable maximum lawful price until the advance payment plus interest has been repaid. That part of the price of delivered gas not received by the producer because of this rule shall be applied in diminution of the amount of the advance payment, plus interest, still outstanding.

DATES: Written comments by June 23, 1980. Public hearing to be held on July 1, 1980, at the address listed below. Other public hearings may be announced.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Refer to Docket No. RM80-52

FOR FURTHER INFORMATION CONTACT:

Roger B. Coven, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4013, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9113

Jeffrey Fink, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8111, 825 North Capitol St., N.E., Washington, D.C. 20426, (202) 357-8460

Issued: April 23, 1980

On November 8, 1978, the Natural Gas Policy Act of 1978 (NGPA) [1] was enacted. The NGPA set various maximum lawful prices for different categories of natural gas. On December 1, 1978, interim regulations were promulgated implementing the NGPA, including a *Special rule regarding carrying charge adjustments for advance payments*, 18 CFR § 271.403. This rule deducted, as a carrying charge adjustment, 83 cents per MMBtu from the maximum lawful price for natural gas qualifying under sections 104 and 106(a) of the NGPA if the seller had accepted advance payments after the issuance of Federal Power Commission (FPC) Opinion No. 770-A, on November 5, 1976.

For gas not subject to sections 104 or 106(a), there is no regulation concerning advance payments. To prevent producers from using advance payments to circumvent the NGPA maximum lawful prices for gas not subject to the current rule in § 271.403, the Federal Energy Regulatory Commission (Commission) proposes to impute an interest rate to all advance payments for such natural gas which are made on or after the date of issuance of this notice.

[1] 15 U.S.C. § 3301 *et seq.*

I. Background

A. *The Advance Payments Program.* On October 2, 1970, the FPC Issued Order No. 410,[2] which allowed interstate pipelines to include advance payments to producers in their jurisdictional rate base. The rationale of this order was that since there were "indications of a natural gas shortage, it is not in the public interest for pipeline companies to bear the cost of assuring themselves and their customers of a future supply of natural gas." [3] The order thus allowed interstate pipelines to grant to producers interest free loans to encourage the dedication of natural gas to interstate commerce, and also allowed those pipelines to pass the burden of the loans to their ratepayers by adding the amount of the advances to the pipeline's rate base. Account 166 was established to include within it "all advance payments made for gas . . . to others . . . for exploration, including lease acquisition costs, development or production of natural gas, when such advance payments are to be repaid by delivery of gas." [4] Advance payments were to be repaid within a five year period. Subsequent orders modified, expanded, and limited the treatment of advance payments in ways not relevant here.[5]

In *Public Service Commission for the State of New York v. F.P.C.*, 511 F.2d 338 (D.C. Cir. 1975), two of the orders establishing the advance payment program were remanded. Subsequently, on December 31, 1975, the FPC terminated rate base treatment for advance payments made under contracts executed after December 31, 1975 (Termination Order).[6] Under the Termination Order, only advance payments made to producers before December 31, 1980, under contracts executed between October 2, 1970, and December 31, 1975, continued to receive rate base treatment.

On November 5, 1976, FPC Opinion No. 770–A was issued. In that opinion the FPC stated:

> We recognize that capital generated through the advance payments program should no longer be required to bring badly needed gas supplies to the interstate market. The rate structure set forth in this Opinion is designated to achieve the capital formation objective.[7]

Although the FPC desired to terminate rate base treatment for all advance payments, regardless of the date of the contract under which they were made, considerations of fairness precluded this action. Instead, the FPC sought to harmonize prospectively the advance paymentsprogram with the rate structure set forth in Opinion No. 770–A by requiring producers to "reduce the sales price of natural gas committed under any further advance payments by the cost of the advances borne by [the pipeline's] consumers."[8] Thus, even though a producer could require an interstate pipeline to make advance payments in accordance with a contract executed prior to December 31, 1975, the producer would probably not require such advances unless necessary capital could not otherwise be obtained.

B. *Advance Payments Under the NGPA.* In *Tennessee Gas Pipeline Co. v. F.E.R.C.*,[9] the District of Columbia Court of Appeals indicated that advance payments "provide a 'bonus' to producers in the amount of the interest factor, an amount which is never

[2] 44 F.P.C. 1142 (1970).

[3] *Id.* at 1144.

[4] *Id.* at 1148. Account 166, *Advances for gas exploration, development and production*, is one of the accounts falling under the heading "Current and Accrued Assets."

[5] The subsequent orders were: Order 410–A, 45 FPC 135 (1971); Order 441, 46 FPC 1178 (1971); Order 465, 48 FPC 1550 (1972); Order 499, 50 FPC 2111 (1973). Order 441 removed rate base treatment for advance payments for exploration and lease acquisition. Order 465 continued to exclude advance payments for lease acquisition from rate base treatment, but reversed Order 441 to allow advance payments for exploration to be included in rate base. Order 499 continued to exclude advance payments for lease acquisition.

[6] Docket Nos. R–411 and RM74–4.

[7] Mimeo at page 150. The "rate structure" referred to above was a substantial increase in the rates which could be charged by jurisdictional natural gas producers.

[8] *Id.*, mimeo at page 151.

[9] 606 F.2d 1094 (D.C. Cir. 1979).

refunded."[10] The court found that this bonus effectively raised the price of natural gas "above the regulatory ceiling."[11] The Commission agrees; without an appropriate adjustment, advance payments may allow producers to circumvent the maximum lawful prices established under the NGPA.

As stated previously, the NGPA established various maximum lawful prices for different categories of natural gas. For gas which falls within NGPA sections 104 or 106(a), the maximum lawful price is established by reference to a "just and reasonable" rate set by the Commission. Opinion 770–A required that "just and reasonable" rates be subject to a carrying charge credit where producers had received advance payments. This carrying charge credit has been continued under the NGPA for gas subject to sections 104 or 106(a). 18 CFR 271.403. As in Opinion No. 770–A, the NGPA deduction applies only to advance payments made on or after 1:00 p.m., EST, November 5, 1976, pursuant to contracts executed after October 2, 1970, and prior to the issuance of the Termination Order on December 31, 1975.[12]

However, natural gas which qualifies for an NGPA pricing category other than sections 104 or 106(a) has a maximum lawful price which is set without reference to "just and reasonable" rates set by the Commission. Therefore, under section 101(b)(5) of the NGPA, which provides that gas qualifying under more than one category shall receive the highest maximum lawful price, this gas would not be subject to the Opinion No. 770–A carrying charge credit. An interstate producer of such gas having an advance payment contract executed after October 2, 1970 and before December 31, 1975, currently has as incentive to demand advance payments from an interstate pipeline. Under such a contract, the interstate pipeline would be bound to make the advance payment, and under the Termination Order, it would be allowed to include any payment made before December 31, 1980, in its rate base. The Commission believes that permitting advance payments without an appropriate adjustment for interest may allow producers to circumvent the maximum lawful prices under the NGPA. This is true for both the interstate and the intrastate markets. Further, prohibiting only interstate pipelines from making advance payments to producers would create a disparity in bargaining power between the intra- and interstate markets: a producer could get the maximum lawful price plus the benefits of an advance payment from an intrastate purchaser, but only the maximum lawful price from the interstate purchaser. Because the Commission wishes to prohibit circumvention of NGPA maximum lawful prices and to avoid the consequences of a disparity between the interstate and intrastate markets it proposes to apply the proposed rule on advance payments to all first sales not subject to the rule currently embodied in § 271.403.

II. Summary of the Proposed Rule

This proposed rule is not predicated upon a desire to discourage advance payments. Rather, the Commission wishes to prevent producers from circumventing the policy of the NGPA by receiving the maximum lawful price, *plus* another thing of value: the use of capital over time without the payment of interest at a market rate.

To prevent the producer of natural gas not subject to the rule currently embodied in § 271.403 from receiving the advance payment "bonus," the Commission proposes that any such producer who has received the benefit of an advance payment not be allowed to receive more than fifty percent of the applicable maximum lawful price per MMBtu until enough gas has been

[10] *Id.* at 1102.

[11] *Id.* at 1103.

[12] Only these advance payments qualify for rate base treatment under the Termination Order of December 31, 1975.

delivered to repay the advance payment plus interest.[13] That portion of the sale price that is not received by the producer will serve to repay the amount owed (the advance payment plus interest) by the producer to the purchaser. Naturally, the advance payment could be repaid in cash or otherwise. When the entire advance payment plus interest has been repaid, the producer will be allowed to collect the full contract price, up to the maximum lawful price.

The methodology for computing the carrying charge credit under the Natural Gas Act (NGA) differs from the methodology for determining the interest rate to be imputed to advance payments under the NGPA. Under the NGA, the focus was on the cost to the pipeline's customers; the NGA carrying charge credit was designed to reimburse the customers for that cost.[14] Under the NGPA, we are concerned with the value of the advance payment received by the producer because we wish to prevent circumvention of the maximum lawful prices. Therefore, for natural gas not subject to an adjustment under Opinion No. 770–A and § 271.403, the Commission proposes to diminish the amount that a producer can collect by an adjustment which reflects the value of any advance payment made by a purchaser to a seller.

The Commission recognizes that the value of an advance payment may vary from producer to producer, depending on each producer's financial ability to acquire loans or to generate capital by other means. However, we propose to use as a standard the average cost of intermediate-term business loans. We believe that the prime rate most closely approximates the cost of such loans and, consequently, the value of an advance payment to most producers. Further, the prime is easily determined, widely known, and frequently used. Hence, the prime rate not only approximates the value of an advance payment but also is desirable for reasons of administrative convenience. This imputed interest rate will be compounded quarterly in order to reflect more precisely the actual value to a producer of having such capital available for its use.[15] The Commission specifically requests comments on this approach or any other approach which would reflect the value to the producer of an advance payment. In addition, we request comment on the treatment which should be accorded to advance payments which were made prior to the issuance of this notice and are not subject to § 271.403.

An example may help to explain the mechanics of the rule. Assume a producer receives $1,000,000 in advance

[13] For section 104 or 106(a) natural gas, § 271.403 of our regulations requires application of the carrying charge credit at the rate of 83 cents per MMBtu, until "an amount of natural gas has been delivered at the adjusted rate such that the total carrying charge credits equal the amounts lawfully collected by the jurisdictional pipeline as a result of including the advance payments in rate base." The rule in § 271.403 has been retained, but has been renumbered as § 270.207(a).

The price for natural gas that is subject to the adjustment under Opinion No. 770–A will be subject to the entire carrying charge for any advance payment made pursuant to a contract executed prior to December 31, 1975. Therefore, if a section 102 well is drilled with the aid of advance payments which are subject to the 770–A adjustment, the section 102 price would not be diminished by the carrying charge credit. The section 104 or 106(a) wells would bear all of the carrying charge. However, under § 270.207(b) of the proposed rule, if a section 102 well is drilled under the same advance payment contract but with the aid of an advance payment not subject to the 770–A adjustment, the section 102 price for such gas must be reduced.

We request comment on the above stated policy and on the alternatives regarding treatment of advance payments made for section 104 or 106(a) gas which has been reclassified since the time that the advance payment was made.

[14] The carrying charges on advance payments included in rate base were determined by reference to the overall rate of return and the allowances for income taxes for the equity portion of the return.

[15] The prime rate was also applied as the interest rate on refunds and carrying charges in Order No. 47 (Docket No. RM77–22, September 10, 1979). We specifically incorporate that rate in our rule here. In Order No. 47, however, the prime rate was a compromise solution which understated the costs to the ratepayer, overstated the benefits to the seller, and provided an incentive for all parties to seek an early resolution of rate proceedings. The Commission recognizes that the justifications for using the prime rate in this proposed rule are different. We have used the prime rate in the proposed rule because we believe that the prime rate most closely approximates an average of the benefits of advance payments to producers and because it is the rate which is most practical to administer.

payments from a prospective purchaser and begins deliveries a year after the date of the advance payment. Assume further that, based on the compound interest computations of this proposed rule, the value to that producer of the use of the advance payment funds for the one year period between acceptance of the advance payment and the first delivery of gas is $100,000. Finally, assume that the contract price for the gas, $2.00 per MMBtu, equals the maximum lawful price at the time of delivery. Since the producer owes the purchaser $1,100,000 (the $1,000,000 advanced plus $100,000 in interest), the producer can collect only $1.00 per MMBtu (50 percent of $2.00, the maximum lawful price for the gas) until at least 1,100,000 MMBtu of gas has been delivered.[16] Once the advance payment plus interest has been repaid, the producer can collect the full maximum lawful price of $2.00 per MMBtu.

The Commission has included a definition of "advance payment" in the proposed rule. An "advance payment" is any payment made by a purchaser in advance of receipt of natural gas deliveries. Thus, the term "advance payment" includes prepayments, extended front-end advances, or any other form of pre-delivery payment or loan.[17]

Finally, the Commission specifically requests comment on whether, as an alternative to this proposed rule, advance payments should be prohibited outright in both the interstate and intrastate markets.

The Commission emphasizes that § 271.403, proposed to be renumbered as § 270.207(a), remains in effect at this time.

Comment Procedure. Any interested person may submit to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, not later than June 23, 1980, data views and comments in writing concerning the matters herein proposed. An original and 14 conformed copies should be filed with the Commission, and should refer to Docket Number RM80-52. Submissions to the Commission should indicate the name, title, mailing address and phone number of the person to whom communications regarding the proposal should be addressed. Written submissions will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

A public hearing concerning this proposal will be held in Washington, D.C. on July 1, 1980, beginning at 9:30 a.m., and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on June 26, 1980. An additional public hearing may be held in an appropriate city outside of Washington, D.C. if sufficient interest in such a hearing is expressed.

Requests to participate in the hearing should reference Docket No. RM80-52, and include concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:30 p.m. on June 26, 1980. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and

[16] Since 1,100,000 MMBtu probably cannot be delivered in the first day, interest will continue to accrue on the unpaid amount. Thus, more than 1,100,000 MMBtu will have to be delivered to repay in total the advance payment plus interest.

[17] Payments made under "take-or-pay" contracts will not be considered to be advance payments.

as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested persons may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information. Members of the hearing panel will be designated by the Chairman of the Commission.

(Natural Gas Act, as amended 15 U.S.C. 717–717w; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Department of Energy Organization Act 42 U.S.C. 7101–7352, E. O. 12009, 42 FR 46267.)

In consideration of the foregoing the Commission proposes to amend Parts 270 and 271 of Subchapter H, Chapter I, Title 18 Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 270—RULES GENERALLY APPLICABLE TO REGULATED SALES OF NATURAL GAS

1. Subpart B of Part 270 is amended by adding a new section 208 to read as follows:

§ 270.207 Special rule regarding advance payments.

(a) The rate prescribed in § 271.402 for post-1974 gas to which Opinion No. 770–A applies shall be subject to a deduction of 83 cents per MMBtu as a carrying charge adjustment if the seller has accepted advance payments on or after 1:00 p.m., EST, November 5, 1976, under an advance payments contract with an interstate pipeline company and such pipeline company has received rate base treatment of such advance payments made. The resulting adjusted rate shall be employed in the discharge of the obligations of any advance payments accepted on or after 1:00 p.m., EST, November 5, 1976, for all deliveries until an amount of natural gas has been delivered at the adjusted rate such that the total carrying charge credits equal the amounts lawfully collected by the jurisdictional pipeline company as a result of including the advance payments in rate base.

(b) In the case of an advance payment which is not subject to paragraph (a) and which has been accepted by the seller on or after [the date of issuance of the proposed rule], the seller may not accept more than fifty percent of the applicable maximum lawful price as consideration in any first sale of natural gas until the advance payment, plus interest, has been repaid by the delivery of natural gas or otherwise. The interest shall be computed from the date on which the advance payment was accepted, in an amount at least equal to the rate specified in § 154.102(d)(2)(iii)(A) compounded in accordance with § 154.102(d)(2)(iii)(B). That portion of the sales price not collected by reason of this rule shall be applied in diminution of the amount owed by the seller.

(c) "Advance payment" means any payment made by any person to any other person in consideration of an obligation to make future delivery of natural gas in a first sale. For the purposes of this definition, the word "person" includes any affiliate of that person.

PART 271—CEILING PRICES

§ 271.403 [Deleted]

2. Subpart D of Part 271 is amended by deleting § 271.403 in its entirety.

¶ 32,064 Natural Gas; Interim, Retroactive and Refund Filing Requirements

45 F. R. 31418 (May 13, 1980).

18 CFR Part 273

[Docket No. RM80-54]

Natural Gas; Interim, Retroactive and Refund Filing Requirements; Notice of Proposed Rulemaking

May 7, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission hereby gives notice that it proposes to amend interim, retroactive and refund filing requirements under Part 273 of the Commission's regulations. This proposal would eliminate interim and retroactive filing requirements, except where section 4(d) of the Natural Gas Act is applicable, and would change provisions regarding refunds.

DATE: Written comments by June 16, 1980.

ADDRESS: Written comments (14 copies) should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426; Reference Docket No. RM80-54.

FOR FURTHER INFORMATION CONTACT: Dan White, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357-8577; Teresa Ponder, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357-8151

I. Background

Section 503(e) of the Natural Gas Policy Act of 1978 (NGPA), (15 U.S.C. 3414), requires that the Federal Energy Regulatory Commission (Commission) adopt rules or orders to permit with respect to the first sale of gas for which a determination is required the collection, subject to refund, of rates not to exceed the maximum lawful price for which the application has been filed and upon which final action has not been taken. The Commission has the authority under section 503(e)(2)(A) to provide one or more methods of such interim collection and establish the qualifying requirements and authorized collection periods it deems appropriate. Section 503(e)(2)(B) provides that such collections shall be subject to refund, and requires the Commission to prescribe regulations to provide adequate assurance that funds are available for such refunds if, after the determination process has ended, the subject natural gas is determined to qualify for a lower maximum lawful price than that collected under the Commission's interim collection procedures.

The Commission has implemented section 503(e) in Part 273 of its regulations. Part 273 was first issued on an interim basis on December 1, 1978 (43 FR 56448, December 1, 1978). It was reissued with modifications as a final regulation on June 19, 1979, in Order No. 30, Docket No. RM79-53 (44 FR 37431, June 27, 1979).

Although section 503(e) of the NGPA does not require filings with the Commission, except in one case,[1] the

[1] Section 503(e)(1) allows a first seller of natural gas produced from a new well to collect rates permitted under Section 109 if an oath statement is filed. However, a further condition of such collection is that an application for determination concerning the subject natural gas be filed with the appropriate jurisdictional agency before March 1, 1979. Section 273.201 of the regulations implemented section 503(e)(1). Since the period provided in section 503(e)(1) has passed, no filings are now made pursuant to § 273.201. No modification of § 273.201 is proposed herein.

Commission's regulations established interim, retroactive, and interim collection refund filing requirements. Sections 273.202 and 273.203 prescribe requirements for interim collections, subject to refund, of rates up to the maximum lawful price for which a sale is claimed to be eligible while the related final eligibility determination is pending. In such instances a seller must submit certain information, described below, to the Commission prior to making such collection.[2] If the maximum lawful price for a particular first sale is finally determined to exceed the price collected for such sale for any period between the date of filing for the determination and the date on which the eligibility determination became final, § 273.204 provides that seller can retroactively collect the difference to the extent contractually authorized.[3] A seller who makes retroactive collection is obligated to make a retroactive collection filing with the Commission. After an eligibility determination which disqualifies a sale for as high a rate as was collected pursuant to Part 273 becomes final, § 273.302 requires refund of the difference, and the filing of a refund report.

The Commission established these filing requirements in Part 273 partly to ensure that the requirements of section 4(d) of the Natural Gas Act (NGA) (15 U.S.C. 717c) were met. Section 4(d) of the NGA requires that a producer subject to the NGA provide adequate notice to the Commission, the producer's customers, and other interested parties of any proposed change in existing rates for sales of natural gas subject to the NGA. In Order No. 15 [4] the Commission, among other things, concluded that the filing and notice requirements of section 4(d) of the NGA are deemed satisfied if a producer has fulfilled the interim and retroactive collection filing requirements of Part 273. That policy is expressed in § 154.94(i) of the regulations, which was promulgated in its present form by Order Nos. 23 and 23-B.[5]

The Commission's regulations regarding interim collections for the period in which the jurisdictional agency determination is pending are set out in § 273.202, with the applicable filing requirements set forth in § 273.202(d). Section 273.203 contains the regulations governing interim collections where the well determinations are pending Commission review. Filing requirements for these collections are found in § 273.203(c). The filing requirements for both these sections are the same, and the § 273.203(c) filing requirement is deemed met if the § 273.202(d) filing was made.

An interim collection filing made pursuant to either § 273.202 or § 273.203 is required to contain the following:

(i) A statement under oath by the filer that he believes in good faith that the subject natural gas is eligible under the NGPA and Subchapter H for a maximum lawful price not less than that to be collected.

(ii) A duplicate of FERC Form No. 121 submitted to the jurisdictional agency.

(iii) A statement certifying that this filing has been served upon each purchaser.

(iv) A statement certifying that collections under this section will be placed in escrow or secured by a surety bond if the purchaser has so required pursuant to § 273.302(c).

(v) A statement of the extent to which such natural gas was committed and dedicated to interstate commerce on November 8, 1978, and if so committed or dedicated, the just and reasonable rate applicable to such natural gas under the NGA on November 8, 1978; any rate schedules for such natural gas on file with the Commission on

[2] The claimed maximum lawful price may be collected from December 1, 1978, if the application for determination was filed by April 1, 1979, and the filing requirements of § 273.202 are fulfilled.

[3] The maximum lawful price allowable as a result of the final determination of eligibility may be collected retroactively to December 1, 1978, if the application for determination was filed by April 1, 1979.

[4] Order No. 15, Docket No. RM79-4, issued November 17, 1978 (43 FR 55756, November 29, 1978).

[5] Order No. 23, Docket No. RM79-22, issued March 13, 1979, (44 FR 16895, March 20, 1979) and Order No. 23-B, issued June 21, 1979.

November 8, 1978; and the certificate docket number if natural gas was being sold on November 8, 1978, pursuant to a small producer certificate.

The regulations governing retroactive collections are set forth in § 273.204. If a seller makes a retroactive collection, that seller is required to file with the Commission the information specified in § 273.204(c)(3), which includes:

1. A notice specifying the total amount to be collected and the amount of and basis for any carrying charges;

2. A statement that the seller has paid all refunds then due to such purchaser under Part 273;

3. A statement of concurrence in the filing signed by such purchaser from whom retroactive collections are made.

4. A copy of any written carrying charge agreement pursuant to which carrying charges are collected.

Section 273.302 sets forth regulations governing refunds of interim collections. The filing requirements are found in § 273.302(e)(3):

Within 30 days after making a refund under this subpart, the seller shall file with the Commission:

(i) The original and two copies of a refund report showing separately the amounts to be refunded and the appropriate interest paid thereon, and

(ii) The original and two copies of a release from the purchaser showing that refunds have been paid.

In 1979 approximately 71,000 filings were made pursuant to Part 273. At present, the Commission is receiving approximately 800 such filings a month.

II. Discussion

The Commission believes that the interim and retroactive collection filings presently required are not, in fact, necessary to assure that the collected rates do not exceed the applicable maximum lawful price, or to assure that funds are available for refunds of interim collections when necessary. However, filings are necessary to satisfy the filing and notice requirements of section 4(d) of the NGA whenever rates for sales of gas subject to NGA producer rate schedules are changed. Section 4(d) provides that a natural gas company [6] may not change any rate or charge except after thirty days notice to the Commission and the public.

The processing of the filings made pursuant to Part 273 consumes a significant portion of the Commission's resources. Given the considerations of economy of Commission resources and the need to comply with the provisions of the NGA, the Commission proposes to make the following amendments to Part 273:

1. Eliminate the interim and retroactive collection filings currently required by §§ 273.202(d), 273.203(c) and 273.204(c) except as required by the NGA;

2. Modify the refund report filing requirements found in § 273.302(e), so as to improve the compliance effort; and

3. Amend § 273.302 to provide that any collection under Part 273 constitute an implicit general undertaking.

The Commission estimates that under the regulatory changes herein recommended, the number of interim and retroactive collection filings would be approximately 75 a month and would decline over time to a minimal number.

A. Elimination of Interim and Retroactive Filings Except Where Necessary Under the NGA

In monitoring collections made pursuant to Part 273, the Commission follows procedures designed to ensure that appropriate refunds will be made if the subject natural gas is determined not to be eligible for the price for which application was filed. The information collected under the interim filing requirements of Part 273 does not aid in the implementations of this compliance program.

As mentioned above, the filing requirements of Part 273 do serve to

[6] The NGA defines a natural gas company in section 2(6) (15 U.S.C. 717a) as a person engaged in the transportation of natural gas in interstate commerce or the sale in interstate commerce of such gas for resale.

satisfy filing and notice requirements of section 4(d) of the NGA. Under § 154.94 of the Commission's regulations, a producer must file with the Commission a notice of rate change for a sale under a producer rate schedule. In Order No. 15, the Commission recognized that natural gas subject to the NGA remains subject to the NGA until that gas receives a final determination that it qualifies under section 102(c), 103, or 107(c)(1) through (4) of the NGPA. In that same order the Commission promulgated § 154.94(i) which stipulates that for rate changes which would otherwise require a notice of rate change filing, the requirements of section 4(d) of the NGA and § 154.94 of the regulations would be deemed satisfied for gas eligible for interim or retroactive collection if the proposed filing requirements of Part 273 are fulfilled. In that same order, the 30 day notice requirement was waived.

In Order No. 25,[7] the Commission determined that one notice of rate change may be filed for each rate schedule to indicate that the producer intends to collect the maximum lawful prices applicable under sections 102(d) or 108 for the sale of any volume of gas which has been determined to qualify under section 102(d) or 108. The Commission believes it is appropriate to provide similar treatment for interim and retroactive collection.

Thus, under the proposed rule, a section 4(d) notice of intent to make an interim or retroactive collection under Part 273, need only be filed once for each NGPA category under a given schedule. Accordingly, to fulfill the requirements of section 4(d) of the NGA an interim or retroactive collection filing is required only if such a filing for the applicable rate schedule(s) has not been previously made. Additionally, the Commission does not intend to require such retroactive filing requirements if the provisions of the NGA do not continue to apply to the first sale of gas after the final determination has been made. (*See*, section 601(a)(1)(B) of the NGPA.) In this proposal: (1) A filing with the Commission is required for making interim or retroactive collections only if the sale is subject to a producer rate schedule; and (2) Such a filing is required only if a notice of intent to make interim or retroactive collection of the price applicable under the NGPA category for which application has been filed has not been previously filed under the applicable rate schedule. A prior filing of an intent to make interim or retroactive collection for sales of gas subject to the same rate schedule and the same NGPA category constitutes such a previous filing.

The Commission proposes to amend the filing requirements found in §§ 273.202, 273.203, and 273.204 to reflect the policy discussed above and requests comments on those proposals. The Commission will also consider and requests comment on whether producers should be permitted to make a blanket filing indicating an intent to make all applicable NGPA interim and retroactive collections under the NGA rate schedule, or whether, under the NGA, producers with rate schedules on file with the Commission may be relieved of the obligation to make any interim and retroactive collection filings.

B. Modification of the Refund Report Filing Requirements of § 273.302(e)

Under the present regulations, only first sellers who actually make refunds are required to file refund reports. The Commission proposes that § 273.302(e) of its regulations be modified to require that whenever an application for determination is withdrawn from the Commission or a jurisdictional agency, or such application receives a final determination that the subject natural gas is not eligible for the applied-for well category, the seller must file either a refund report or a statement that no refunds of interim collections are required. The proposal would enhance the value of these reports as they assist the Commission in monitoring

[7] Order No. 25, Docket No. RM79-31, issued March 27, 1979.

compliance with the NGPA. This requirement would also reduce the amount of investigative work which the Commission staff currently undertakes to ensure that refunds are made where required. Filings made pursuant to § 273.302 would still be required to include a statement of concurrence executed by the purchaser. The Commission requests that comments address whether other methods of assuring refunds are feasible, as well as the proposal contained in this docket.

C. Amendment to § 273.302 Providing That Any Collection Under Part 273 Constitutes an Implicit General Undertaking

Under Part 273 as it currently reads, the interim and retroactive filings serve as a general undertaking agreement by operation of § 273.302(b). This section presently provides that any collection filing made pursuant to part 273 for a first sale of natural gas constitutes a general undertaking to comply with the refund provisions of Part 273. Inasmuch as the Commission herein proposes in most cases to allow collections pursuant to Part 273 without filings with the Commission, the general undertaking agreement would usually not be applicable. However, the fact that a filing need not be made should not affect the requirement that refunds are required where prices in excess of the applicable maximum lawful price have been collected pursuant to Part 273. Accordingly, the Commission proposes to amend § 273.302(b) of its regulations so that any collection of a price on an interim or retroactive basis under Part 273 would constitute and have the effect of a general undertaking agreement.

At such time as the Commission issues these rules we would make any necessary technical and conforming amendments to the reseller rule, in § 270.202(b)(2). The Commission requests comments as to whether any special considerations need to be given to the effect of this proposal on the reseller rules.

III. Comments Procedures

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol St. N.E., Washington, D.C. 20426. Comments should reference Docket No. RM80-54 on all documents submitted to the Commission. Fifteen (15) copies should be submitted. All comments and related information received by the Commission prior to June 16, 1980, will be considered prior to the issuance of the regulation. Comments are invited on all aspects of this proposal.

Dates and locations of hearings in this rulemaking may be announced in the near future.

(Natural Gas Act, as amended, 15 U.S.C. 717-717w; Natural Gas Policy Act 15 U.S.C. 3301-3432; Department of Energy Organization Act, 42 U.S.C. 7101-7352; EO 12009, 42 FR 46267).

In consideration of the foregoing the Commission proposes to amend Part 273 as set forth below.

By direction of the Commission.

Kenneth F. Plumb,
Secretary.

PART 273—COLLECTION AUTHORITY; REFUNDS

1. Section 273.202 is amended by revising paragraphs (d) and (e), to read as follows:

§ 273.202 Collection pending jurisdictional agency determination of eligibility.

* * * * *

(d) *Conditions.* A seller who makes an interim collection under this section with respect to a first sale of natural gas, must satisfy the following conditions:

(1) The seller shall serve each purchaser with a notice of intent to make interim collections pursuant to this section along with a copy of the FERC Form No. 121 submitted to the jurisdictional agency.

(2) The seller shall place all collections made under this section in escrow or shall secure such collections

by a surety bond, if the purchaser so requires pursuant to § 273.302(c).

(3) If the subject natural gas was committed or dedicated to interstate commerce on November 8, 1978, and subject to a rate schedule on file with the Commission, the seller shall file with the Commission a notice of intent to make interim collections pursuant to this section which specifies the applicable category for which application has been filed under Part 271. Such notice shall also specify the just and reasonable rate applicable to such natural gas under the Natural Gas Act on November 8, 1978, and any rate schedules for such natural gas on file with the Commission on November 8, 1978. For each rate schedule only one notice must be filed for each category under Part 271 for which an application for determination has been filed.

(e) *Limitation.* Upon termination of the interim collection authority under this section for any sale, further collections under this section cannot be made for any sale from the same well.

2. Section 273.203 is amended by revising paragraph (c) to read as follows:

§ 273.203 Collection pending review of jurisdictional agency determination of eligibility.

* * * * *

(c) *Conditions.* Unless the seller has previously complied with the conditions set forth in § 273.202(d), in order to make interim collections under this section with respect to the first sale of natural gas, the seller shall fulfill the conditions described in § 273.202(d)(1) and (3).

3. Section 273.204 is amended by revising paragraph (c) to read as follows:

§ 273.204 Retroactive collection of the final determination.

* * * * *

(c) *Conditions.* In order to make a retroactive collection under this section with respect to a first sale of natural gas a seller must satisfy the following conditions:

(1) Retroactive collections may not begin until 45 days after the eligibility determination becomes final.

(2) A seller may not collect any amount under this section from any purchaser unless the seller has paid to such purchaser all amounts that are due to be refunded under this subchapter by the seller to such purchaser on or before the date on which retroactive collections are made.

(3) If the subject natural gas was committed or dedicated to interstate commerce on November 8, 1978, and was subject to a rate schedule on file with the Commission, and if the provisions of the Natural Gas Act continue to apply to the first sale of the gas after the final determination has been made, the seller shall file with the Commission a notice of intent to make retroactive collections under this Part 273 and shall specify the applicable category under Part 271. Such notice shall also specify the just and reasonable rate applicable to such natural gas under the Natural Gas Act on November 8, 1978, and any rate schedules for such natural gas on file with the Commission on November 8, 1978. One notice must be filed per rate schedule for each category under Part 271 for which a determination has been obtained and for which the rate schedule is applicable.

(4) Collection under this section may be made only to the extent permitted by the applicable sales contract.

(5) Carrying charges may be collected only to the extent provided by a written agreement of the parties to the applicable sales contract (or amendment thereto). The carrying charges shall be computed at an interest rate which does not exceed the rate specified in § 154.102(d).

4. Section 273.302 is revised to read as follows:

§ 273.302 Refunds of interim collections.

(a) *Applicability.* The provisions of this section apply to any interim collections made under the authority of Subpart B of this part.

(b) *General Undertaking.* (1) Any interim collections under this part shall constitute and have the effect of a general undertaking to comply with the refund provisions of this Part 273.

(2) Additional refund assurance may be required at any time by order of the Commission.

(c) *Escrow.* If the purchaser so requires, any amount (i) which is collected under § 273.202; and (ii) which (A) in the case of a new well, is in excess of the price specified in § 273.201(a)(1); or (B) in the case of any other well, is in excess of the otherwise applicable maximum lawful price, shall be secured by a surety bond or held in escrow, in a form satisfactory to the purchaser.

(d) *Records.* (1) If any collection is made under Subpart B, the seller shall keep accurate accounts of:

(i) All amounts so collected for each billing period and for each purchaser;

(ii) Resulting revenues as computed under the price being charged pursuant to this part;

(iii) The price charged immediately prior to any interim collections; and

(iv) The price prescribed by § 273.[illegible] (or any other maximum lawful price used to compute the amount collected under Subpart B), together with the differences in revenues so computed for each sale.

(2) Such books and records shall be retained for a period of 3 years after the termination of the interim collection period. Any contract under which any interim collections have occurred must be maintained and preserved for at least 3 years after expiration.

(e) *Refund payment.* (1) Within 45 days after an eligibility determination that a first sale is not at least eligible for the price collected under this part becomes final, or an application for determination is withdrawn by an applicant while the application is before the Commission or the jurisdictional agency, the seller shall refund to the purchaser by cash or check the refund amount computed under paragraph (h) of this section together with interest determined in accordance with § 154.102(d), on the excess collections that have been collected from the date of payment until the date of refund.

(2) No interest is required to be paid on any portion of a refund:

(i) Which represents payments of royalties or taxes to Federal or State governmental authorities, except to the extent that such authorities pay interest to the seller when refunding overpayments of royalties or taxes; or

(ii) Which is paid from escrow except that interest which accrued in the escrow account on the amount required to be refunded shall be paid at the time of refund.

(f) *Filing requirements.* (1) Within 75 days of either the date a final determination of eligibility is obtained that a sale is not at least eligible for the price collected under this part, or the date the application for determination is withdrawn by the applicant while the application is before the Commission or the jurisdictional agency, the seller shall file with the Commission either:

(i) A refund report stating separately the amounts required to be refunded pursuant to paragraph (h) of this section and the appropriate interest to be paid thereon, in accordance with paragraph (e) of this section; or

(ii) A statement certifying that no refund payment is required pursuant to paragraph (e) of this section.

(2) A filing made pursuant to this paragraph shall include a statement of concurrence in the filing signed by the purchaser.

(g) *Discharge of obligation.* If an eligibility determination that natural gas is eligible for the price for which the application for determination was filed becomes final, then at such time, the bond, escrow, or undertaking shall be discharged to the extent it applies to first sales from the well for which the determination was made. If any refunds required by this section are made in conformity with the terms and conditions of the bond, escrow, or undertaking, the bond, escrow, or undertaking shall be discharged insofar as it applies to such refund obligation.

(h) *Refund computation.* (1) Where the final eligibility determination that the sale is not at least eligible for the price collected under Subpart B also includes a final eligibility determination of the maximum lawful price for that sale, that finally determined price, to the extent permitted by the applicable sales contract, shall be used to compute the excessive interim collections and refund amount.

(2) In any other case, the applicable maximum lawful price specified under Subpart D, E, F, or I of Part 271, to the extent permitted by the applicable sales contract, shall be used to compute the excessive interim collections and refund amount.

¶ 32,065 Procedures Governing Applications for Special Relief Under Sections 104, 106 and 109 of the Natural Gas Policy Act of 1978

45 F. R. 31744 (May 14, 1980).

18 CFR Parts 2 and 271

[Docket No. RM79-67]

Procedures Governing Applications for Special Relief Under Sections 104, 106 and 109 of the Natural Gas Policy Act of 1978

May 9, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission is giving notice of proposed regulations establishing substantive standards for granting special relief rates to encourage the production of natural gas that would not be produced at applicable NGPA maximum lawful prices. These rates would be granted under the Commission's authority to grant higher just and reasonable rates for gas subject to sections 104, 106 and 109 of the NGPA.

The Commission received public comments on a Notice of Proposed Rulemaking in this docket, issued August 14, 1979. On January 16, 1980, the Commission issued a staff draft of a final rule which set out both substantive and procedural rules governing applications for special relief, and solicited further public comment on certain issues raised in the staff draft.

In this notice the Commission is soliciting comments on newly proposed §§ 271.1001–271.1006 of Subpart J, which set out proposed regulations governing standards of applicability for special relief, definitions, conditions of eligibility, methods of rate computation and the maximum special relief rate. The Commission believes that public comments received in prior public proceedings have fully explored the issues related to procedural and administrative aspects of special relief, and does not solicit further comments on these provisions.

DATE: Written comments are to be submitted by June 9, 1980.

ADDRESS: Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Reference Docket No. RM79–67.

FOR FURTHER INFORMATION CONTACT:

Susan Tomasky, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8461

Lou Engel, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8667

Procedures governing applications for Special Relief Under Sections 104, 106 and 109 of the Natural Gas Policy Act of 1978, Docket No. RM79–67.

On August 14, 1979, a Notice of Proposed Rulemaking in this docket was issued proposing administrative procedures and substantive standards governing applications for special relief. [1] In that notice, the Commission proposed to implement its authority under the Natural Gas Policy Act of 1978 (NGPA) to establish higher just and reasonable rates for gas subject to maximum lawful prices under sections 104, 106 and 109 of the NGPA.

In January 1980, the Commission published a staff draft of a final rule, [2] and solicited further public comment on certain issues raised by the staff draft. Specifically, the Commission requested comments on the two-stage procedure described in the staff draft for review of special relief applications and on the appropriate rate of return on investment

[1] 44 FR 49468 (August 23, 1979).

[2] Notice of Request for Public Comment and Notice of Public Discussion, (issued January 16, 1980); 45 FR 5321 (January 23, 1980).

for gas from special relief projects. The Commission also asked commenters to discuss whether an applicant should be required to make a binding election to receive only the special relief rate for gas produced from the special relief project and whether the Commission should set a ceiling on rates granted under special relief.

In this notice of proposed rulemaking, the Commission is requesting comment on newly proposed §§ 271.1001–.1006 of subpart J, which set out the substantive standards for determinating special relief rates. We believe that comments received in the prior public proceedings have fully explored the issues related to administrative procedures, retroactive collection, and filing requirements, and we therefore do not request additional comment on these provisions as previously proposed.

I. The Proposed Rule

Under the proposed regulation, a first seller may apply for a cost-based rate for natural gas subject to a maximum lawful price under sections 104, 106 or 109, where it is expected that the costs of additional investment, or of ongoing operating and maintenance expense, would not be compensated for at the applicable NGPA rate. Applicants for special relief, of for optional pricing certificates under prior Commission regulations, [1] would be permitted to pursue their pending applications under the provisions of this regulation.

Special relief would be available for new investment projects, and for wells for which there is no planned investment. In the case of a new investment project—either production enhancement work on a previously producing well or wells, or a new production project—the special relief rate is calculated to permit recovery of and return on investment costs in addition to recovery of ongoing operating and maintenance expense. The regulation also provides for a special relief rate designed to permit recovery of the operating and maintenance expenses of existing wells for which no new investment is planned, plus an incentive allowance on those expenses.

A. *Applicability.* This rulemaking provides special relief for natural gas subject to a maximum lawful price under section 104, 106 and 109, on the basis of the Commission's authority to prescribe higher just and reasonable rates for gas subject to those sections. Several comments received in response to the August notice of proposed rulemaking urged the Commission to extend special relief to other categories of natural gas, particularly gas subject to section 105.

The Commission is requesting further comment on its authority to provide a higher just and reasonable rate for natural gas subject to maximum lawful prices under other sections of Title I. Specifically, comments should discuss the extent to which the Commission may use its incentive pricing authority under section 107(c)(5) to establish just and reasonable rates for gas from production enhancement projects and existing wells where on-going operating and maintenance expenses exceed the applicable maximum lawful price. Also, commenters are requested to discuss the extent to which a just and reasonable rate, within the meaning of the Natural Gas Act, need not be cost-based.

B. *Definitions.* Section 271.1002 sets out definitions for this subpart. Paragraph (a) defines new investment project as a new production project or a production enhancement project. Section 271.1002(b) provides that a new production project may be an individual well or a platform and wells drilled thereon. Alternatively, under § 271.1002(b)(iii), a producer may designate any combination of wells or facilities as a new production project, and may receive a special relief rate computed on the basis of project costs incurred after designation. Also a producer who has included a number of wells or facilities in a special relief or optional procedure application now

[1] 18 CFR 2.56a(g), 2.56b(h), 2.75, 2.76, and 2.77.

pending before the Commission[4] may pursue the application as one for a new production project to obtain for a special relief rate applicable to *all* wells and facilities included in the pending application. In such a case, the new production project would include only that investment incurred after the pending application was filed.[5]

Section 271.1002(b) defines a pending application as an application filed prior to April 16, 1980, the date that the Commission agreed in principle to issue these substantive standards as a Notice of Proposed Rulemaking. The Commission believes that applicants who file subsequent to that date have sufficient notice of the rules which will govern their application. Section 271.1002 also defines, for purposes of subpart J, the terms "production enhancement project," "related production facilities," "first seller," and "small project."

C. *Eligibility.* Section 271.1003 would establish the terms of eligibility for special relief. Under § 271.1003(a), a first seller may apply for special relief for natural gas from a new investment project, or for a well for which there is no planned investment. Also, under § 271.1003(b), a first seller who has filed a pending application may give notice of intent to proceed with his pending application.[6]

The Commission is aware, however, that offering special relief to first sellers would in many cases deny special relief to pipeline producers, because a pipeline's sale of natural gas which is not exclusively attributable to the pipeline's own production is not a first sale under the NGPA.[7] The Commission specifically requests comments discussing whether special relief should be available to pipeline producers, and whether the substantive provisions set out in this notice are appropriate for computing special relief rates for pipeline producers.

As a further condition of eligibility for special relief, a producer, at the time of application and prior to the commencement of any new investment, would be required under § 271.1003(c) to elect to receive only the cost-based special relief rate for gas produced from the well or project. This election would preclude a producer who applies for a special relief rate from subsequently filing for or collecting a higher price under any other provision of the NGPA. The election would also be binding on the applicant's successors in interest.

This election is intended to insure that special relief will work to complement the pricing scheme of Title I of the NGPA, by providing price incentive which induce the development of gas reserves that would not be produced at applicable NGPA prices. Absent the requirement of a binding election, a producer who finds the NGPA price to be ample incentive to undertake a particular project may nevertheless be

[4] Under §§ 2.56a(g), 2.75, 2.76 or § 2.77.

[5] Applicants with pending applications may wish to seek special relief under this subpart for only a portion of the wells or facilities included in the original application, rather than for all wells and facilities originally included. Nothing in these proposed provisions is intended to preclude such a applicant from pursuing special relief applications for such wells or facilities on a well-by-well or platform basis. In this situation, the application for each well or platform would be considered a pending application. *See* discussion *infra* of § 271.1004 regarding pending applications for new production projects comprised of individual wells or platforms.

[6] Under the procedural scheme set out in the August Notice of Proposed Rulemaking, the applicant would be required to submit, in the form of conforming filings, any additional information necessary for Staff review of a special relief application. *See* Notice of Proposed Rulemaking, § 271.1004(c)(3), (issued August 14, 1979); 44 FR 49468, 49474 (August 23, 1979).

[7] Section 270.203(a) of the Commission's regulations. *See*, Order No. 58, *mimeo* at 3–4 (Docket No. RM80–7, issued Nov. 14, 1979); 44 FR 66577, 66580 (November 20, 1980). A sale of a pipeline's own production is a first sale if it is an off-system sale, or if the gas is produced from an identifiable well and committed by contract to a particular purchaser. In such a case, the pipeline-producer would be eligible for special relief for gas from the well or project. However, a large proportion of pipeline production is commingled with purchased gas prior to sale, and thus is not subject to first sale treatment, *id.* As a result, a pipeline ordinarily would be precluded from seeking special relief for commingled volumes.

tempted to apply for special relief as insurance against substantial cost-overruns or inadequate reserves. Then, at the completion of the investment, the producer would simply choose the higher of the special relief rate or the applicable NGPA rate. As a result, the higher special relief rate would often serve merely to guarantee a recovery of and a certain return on the costs of successful ventures, rather than to induce investment that would not be undertaken at NGPA prices.[8]

D. *The Special Relief Rate for New Investment Projects.* The proposed methods of computation and the substantive standards for determining special relief rates for new investment projects are set out in § 271.1004. In the case of future applications for new production projects, the proposed regulation provides for recovery of and return on incremental investment, other than lease acquistion costs, incurred subsequent to the date of application. This sunk cost exclusion is premised on the view that the date of application represents the point at which the producer must decide whether or not to undertake additional investment, and therefore, is the point at which the assurance of a cost-based rate for gas produced from the project may provide a meaningful inducement to additional investment. Under this provision, a producer electing special relief immediately after lease acquisition could recover all costs associated with exploration and development.

However, because the Commission's prior practice encouraged pending applicants for what would now be defined as new production projects to apply at the completion of their investment, the date of application does not represent the point at which the availability of special relief induced those producers to undertake further investment. Therefore, in the case of pending applications for new production projects comprised of individual wells or platforms, the special relief rate would be based upon all costs incurred, exclusive of lease acquisition costs.

In the case of both pending and future applications for production enhancement projects, only costs incurred after the date of application may be included in the rate. This rule is consistent with prior Commission practice.

The proposed regulation would permit a producer to choose either of two methods of computing a special relief rate for new investment projects. The first method, described in §§ 271.1004 (b) and (c), would require the Commission to determine a special relief rate composed of a capital recovery component and an operating and maintenance expense component. The capital recovery component would provide for the recovery of all eligible project costs and a return on that investment after Federal income taxes. The Commission would compute this component using the discounted cash flow (DCF) method on the basis of volumes of gas estimated to be produced over the life of the project. To avoid any windfall that may result if the actual volumes prove to exceed the estimated reserves, the special relief rate would not include the capital recovery component for volumes delivered in excess of 110 percent of the estimated reserves. The rate for the excess volumes would be equal to the operating and maintenance expense component. The Commission specifically requests comments on its proposal to terminate the capital recovery component for excess volumes of gas.

Section 271.1004(c) sets out a formula for computing a "tilted" operating and maintenance expense component which escalates periodically to provide the recovery of current operating and maintenance expense. The operating and maintenance expense component for the initial delivery period (the period preceding and including the first

[8] The staff memorandum published in connection with the January Notice of Request for Public Comment, *supra*, note 2, contains a fuller discussion of issues related to the election requirement.

calendar month of delivery) would be computed on the basis of the first year's estimated volumes and operating expenses. The rate would be recomputed monthly according to a formula set out in the regulation, which would adjust the rate for the previous month to account for any fluctuation in volumes and inflation.

As an alternative, the producer may choose to seek authority to collect a contract price, negotiated with his purchasers, to provide for capital recovery and the recovery of operating and maintenance expense. The contract price would include a capital recovery component which would provide for the recovery of and return (after Federal income taxes) on actual investment costs; the terms of the contract would specify the period of time, or volumes of production, over which the capital component would be recovered. The operating and maintenance expense component would be calculated using the "tilt" method described above. Commission review would be limited to a staff review of actual costs to determine that they include only eligible investment, *i.e.*, exploration and development costs in the case of a pending application, and incremental costs in the case of a future application.

The producer would be required to keep accounts which show the recovery of the capital recovery component over the period of time or volumes of production specified in the contract. No capital recovery including the applicable return on investment would be permitted beyond the specified time period of recovery, or of production volumes in excess of 110 percent of the original estimates (whichever is applicable under the contract). When the capital recovery component is terminated, the producer would forward to the Commission the records which were maintained to show the recovery of investment. The Commission specifically requests comment on this alternative method of rate computation.

Section 271.1004 provides for a rate of return equivalent to the rate of return established in the 1976 nationwide ratemaking under Opinion No. 770, adjusted to account for fluctuations in the investor's cost of capital. The fifteen percent rate of return adopted in Opinion No. 770, and used in subsequent special relief and optional procedure cases, was computed on the basis of 1975 financial data. The fifteen percent figure can be reduced to the 1975 yield on ten-year constant maturity U.S. Treasury bonds (7.99%), plus a seven percent risk premium

On this basis, the Commission proposes to provide a rate of return which is equal to the sum, rounded to the nearest one-half percentage point, of a seven percent risk premium and the yield on ten-year constant maturity bonds for the calendar year prior to the year in which application for special relief is made.[9] This computation offers the producer the same risk premium implicit in the 1976 national rate. The portion of the rate which corresponds to the return on ten-year government bonds is intended to assure the recovery of the producer's current cost of capital as of the time of application.

The rate of return would be computed in the same manner for both pending and future applications. For example, a producer who files an application for special relief in calendar year 1980 would receive a 16.5 return on investment; a producer who has currently pending an application which was filed in 1979 would receive a 15.5 return on investment.

E. *The Special Relief Rate for Wells for Which There is No Planned Investment.* In the case of a well for which there is no planned investment, the special relief rate would provide for the recovery or operating and maintenance expenses computed under

[9] These data are published annually by the Federal Reserve Board in the February issue of the Federal Reserve Bulletin. In order to provide a more current reflection of the producer's cost of capital, the rate of return could be indexed to reflect the yield on ten-year bonds for the four calendar quarters or the twelve months preceding the date of application. If the Commission chooses to index the rate on a quarterly or monthly basis, the Commission would publish the applicable rate for each quarter or for each month.

the "tilt" method described above. In addition, the producer would be granted a five percent return after Federal income taxes on such expenses. This return is intended as an incentive allowance, to encourage the continued production of flowing gas, where the recovery of only out-of-pocket expense may be less attractive to the producer than the resulting salvage value if the well were abandoned.

F. *The Maximum Special Relief Rate.* Underlying the establishment of a special relief program is the belief that the Commission should use its authority to grant cost-based rates to encourage the production of high cost or high risk natural gas to the extent that such production is economically efficient. The Commission sees no benefit in inducing the production of natural gas which can only be produced at prices in excess of the Btu equivalent price of alternative fuels. Therefore, § 271.1006 of the proposed regulation provides that the special relief rate may not exceed the average refinery acquisition cost of imported crude oil, for the month in which the special relief application is filed, or, if greater, the first month in which gas from the special relief project is delivered. Under the proposed regulation, the maximum special relief rate for any month would be determined by converting the national average refinery acquisition cost of imported crude oil [10] by a Btu conversion factor of 5.8 MMBtu's per one barrel of oil.

II. Written Comment Procedures

The Commission invites interested persons to submit written comments on the matter proposed in this notice. An original and 14 conformed copies of such comments should be filed with the Commission by June 9, 1980. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. All comments should refer to Docket No. RM79–67.

The Commission requests that commenters who have already submitted comments in this docket limit their discussions to matters which they have not fully addressed in earlier submissions. As noted above, the Commission believes that the issues relating to administrative procedures, interim collections, and filing requirements have been fully explored in earlier public proceedings. However, to the extent that a commenter's views on proposed §§ 271.1001–.1006 are influenced by procedural considerations, we welcome further articulation of those considerations. Commenters are also requested to specify the section of the regulation to which their comments are addressed.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426. The Commission will consider all timely comments before acting on the matters proposed in this notice.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; Exec. Order No. 12009, 42 FR 46267).

In consideration of the foregoing Parts 2 and 271 of Chapter I, Title 18, Code of Federal Regulations are proposed to be amended as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 2—GENERAL POLICY AND INTERPRETATIONS

§§ 2.56a, 2.56b [Amended]; 2.75, 2.76, and 2.77 [Deleted]

1. Part 2 is amended in the Table of Contents where appropriate and in the text of the regulations by deleting §§ 2.56a(g), 2.56b(h), 2.75, 2.76, and 2.77. Paragraphs (h) through (p) of § 2.56a are

[10] These data are published in the Monthly Entitlements Notice, issued by the Economic Regulatory Administration of the Department of Energy pursuant to 10 CFR 211.67(i).

redesignated as paragraphs (g) through (o). Paragraphs (i) through (n) of § 2.56b are redesignated as paragraphs (h) through (m).

PART 271—CEILING PRICES

§ 271.402 [Amended]

2. Part 271, Subpart D is amended by deleting § 271.402(c)(3).

Subparagraph (4) of § 271.402(c) is redesignated as paragraph (3).

3. Part 271 is further amended in the Table of Contents by deleting "Subpart J—[Reserved]" and substituting the following in lieu thereof:

Subpart J—Special Relief

Sec.
271.1001 Applicability.
271.1002 Definitions.
271.1003 Eligibility.
271.1004 Special relief rate for new investment projects.
271.1005 Special relief rate for a well for which there is no planned investment.
271.1006 Maximum special relief rate.
271.1007 Application.
271.1008 Intervention.
271.1009 Review by staff.
271.1010 Determination by the Director of the Office of Pipeline and Producer Regulation.
271.1011 Appeals to the Commission.
271.1012 Retroactive collection.
271.1013 Filing requirements.

Authority: Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; Exec. Order No. 12009, 42 FR 46267).

Subpart J—Special Relief

§ 271.1001 Applicability.

This subpart sets forth the conditions under which special relief may be obtained for any natural gas which is subject to a maximum lawful price under section 104 or 106, (whether or not such gas qualifies under any other section of the NGPA) or 109 of the NGPA, except that this subpart does not apply to natural gas produced from the Prudhoe Bay unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

§ 271.1002 Definitions.

For purposes of this subpart:

(a) "New investment project" means a new production project or a production enhancement project.

(b)(1) "New production project" means

(i) An individual well;

(ii) An individual platform, and wells drilled thereon; or

(iii) Investment in any wells or facilities designated in a special relief application under this subpart or included in a pending application, which investment was incurred subsequent to such designation or inclusion.

(2) A new production project may not include any well which produced oil or natural gas in commercial quantities more than 60 days before the date of application, absent waiver by the Director for good cause.

(c) "Production enhancement project" means investment for maintenance, increase, or restoration of production of a well which produced oil or natural gas in commercial quantities before the date of application (or a group of such wells). Such terms include reconditioning workover, deeper drilling, replacing or adding major equipment or related production facilities, or any other additional work necessary to prevent the loss of gas production or reserves.

(d) "Related production facilities" means the equipment and facilities of the first seller which connect the wellhead to the purchaser's facilities.

(e) "First seller" means a seller in a first sale, except that it shall exclude a reseller as defined in § 270.202(e).

(f) "Small project" means a new investment project which meets the following criteria at the time an application for special relief is made, or in the case of a pending application, at the time conforming filings are made under the procedures for application under this subpart:

(1) The proposed new investment will result in estimated additional revenues (at the proposed rate) over the life of the

project to the applicant of less than 100,000 times the proposed rate; and

(2) The proposed new investment exceeds 25 percent of the estimated additional revenues (at the proposed rate) to be generated by the project.

(g) "Director" means the Director of the Office of Pipeline and Producer Regulation.

(h) "Pending application" means an application filed before April 16, 1980, under §§ 2.56a(g), 2.56b(h), 2.75, 2.76 or 2.77.

§ 271.1003 Eligibility.

(a) *General rule.* Except as otherwise provided in paragraph (b) of this section, a first seller may apply for a special relief rate under this subpart for natural gas produced from:

(1) A new investment project; or

(2) A well for which there is no planned investment.

(b) *Pending applications.* A first seller who has filed a pending application may, in accordance with procedures for application under this subpart, file notice of intent to proceed with such application for a special relief rate under this subpart.

(c) *Election not to receive higher rate.* In order to apply for a special relief rate under this subpart, the first seller must elect not to file for, or collect, under any provision of this subchapter (other than this subpart), a rate which is higher than the applicable rate under this subpart. Such election is binding on the first seller and any successor in interest to the first seller.

§ 271.1004 Special relief rate for new investment projects.

(a) *Computation of rate.* Except as provided in § 271.1006, the special relief rate for a new investment project, other than a small project, at the election of the applicant shall be:

(1) The contract price for sale of natural gas from the project, subject to the provisions of paragraph (e) of this section; or

(2) The rate, in cents per unit of production (MMBtu), which is the sum of the following two components:

(i) A capital recovery component, determined under paragraph (b) of this section; and

(ii) An operating expense component, determined under paragraph (c) of this section.

(b) *Capital recovery component*—(1) *General rule.* The capital recovery component of the special relief rate shall be determined using the discounted cash flow method (described in the Appendix to this subpart) and shall be constant over the life of the project (unless terminated under subparagraph (5) of this paragraph).

(2) *Computation.* The values used in the discounted cash flow computation shall reflect:

(i) Subject to subparagraph (4) of this paragraph, any investment in the project (exclusive of lease acquisition costs and costs incurred prior to lease acquisition);

(ii) The net working interest (gross interest less royalty interest) production (in MMBtu's) of all natural gas and other hydrocarbons estimated to be produced over the life of the project;

(iii) Depreciation computed on a unit of production (MMBtu) basis;

(iv) A discount rate equal to the sum, rounded to the nearest one-half percentage point, of 7 percentage points plus the average ten year constant maturity interest rate on U.S. Treasury bonds for the calendar year prior to the calendar year in which the application is filed, as published in the *Federal Reserve Bulletin;*

(v) An allowance for Federal income tax which is attributable to the taxable income from the project (after consideration of any applicable percentage depletion allowance). This tax allowance shall be determined by applying the statutory rate applicable to such taxable income of the investor. Any investment tax credits generated by the investment incurred in completing the project will be taken into account in the discounted cash flow computation of the investment.

(3) *Investment prior to delivery.* Except for purposes of subparagraph (4) of this paragraph, investment incurred prior to one year before the commencement of deliveries

attributable to the project shall be treated as if incurred on the date one year prior to the commencement of deliveries, absent reasonable justification.

(4) *Costs incurred prior to application.* In the case of a pending application for a production enhancement project, or an application for a new investment project under this subpart, no costs shall be included which were incurred prior to the date such application was filed.

(5) *Termination of capital recovery component.* No capital recovery component may be included as a part of a special relief rate for deliveries in excess of 110 percent of the amount of natural gas estimated to be produced over the life of the project under paragraph (b)(2)(ii) of this section.

(c) *Operating expense component.* The operating expense component of the special relief rate shall be determined for each calendar month as follows:

(1) By using the formula:

$$Rc = \frac{Rp \times I \times Vp}{Vc}$$

Where:

Rc = The rate for the current month;
Rp = The rate for the previous month in which production occurred;
I = The inflation adjustment for the current month as published by the Commission under § 271.101(c);
Vp = Actual gross volume (Mcf) of gas delivered during the previous month in which production occurred;
Vc = Actual gross volume (Mcf) of gas delivered during the current month.

(2) For the initial delivery period (the period prior to and including the first full calendar month) the rate for the previous month (Rp) shall be determined by dividing the first year's estimated operating expense as determined under clause (4) of this subparagraph, by the net working interest (gross interest less royalty interest) production (in MMBtu's) of hydrocarbons estimated to be produced during the first year of the eligible project.

(3) For the initial delivery period (the period prior to and including the first full calendar month) the actual gross volume (Mcf) of gas delivered during the previous month (Vp) shall be the annualized (divided by 12) gross volume of gas estimated to be produced during the first year of the project.

(4) The first year's estimated operating expense shall be estimated for the first year in which deliveries are made under the special relief rate, according to the following standards:

(i) Operating expenses shall be estimated on the basis of normal, recurring operating and maintenance expenses, incurred and charged on the books and records of the producer for the production of hydrocarbons from the project;

(ii) Regulatory expense shall be determined by multiplying the estimated first year's net working interest (gross interest less royalty interest) gas production (in MMBtu's) by $.001;

(iii) A return on working capital including an allowance for Federal income tax thereon shall be determined by multiplying the estimated operating expense as defined in this clause (exclusive of regulatory expense and return on working capital) by a 12.5 percent working capital allowance times the applicable percent rate of return and dividing the product by a divisor of one minus the tax rate applicable to the applicant under subparagraph (2)(v) of this paragraph.

(iv) Operating expense shall not include capital investment, depreciation, depletion, amortization, return on investment (profit), amounts repaid on borrowed funds, State income taxes, Federal income tax (except as allowed for in subdivision (iii) of this Subparagraph), any overhead which is not directly related and charged to the eligible project, and any other adjustments allowed under subpart K of this part.

(v) Only those expenses shall be considered which are to be prudently incurred and which are in line with comparable industry expenditures for such equipment, services and expenses for similar projects.

(d) *Small projects.* The special relief rate proposed for a small project (exclusive of State severance tax, as defined in § 271.1001(a)) may not exceed

the applicable rate for large producer sales under section 106(a) of the NGPA.

(e) *Alternative special relief rate.*—(1) *Computation.* Except as provided in § 271.1006, a first seller may elect to receive, instead of the special relief rate computed under § 271.1004(b)–(c), a price determined by contract negotiation that is no greater than the sum of:

(i) A capital recovery component which includes:

(A) Actual investment costs, other than costs incurred prior to lease acquisition, lease acquisition costs, and, in the case of applications under this subpart, costs incurred prior to date of application;

(B) A return on such investment costs computed in accordance with § 271.1004(b)(iv); and

(C) An allowance for Federal income tax computed in accordance with § 271.1004(b)(v); and

(ii) An operating and maintenance expense component, computed in accordance with § 271.1004(c).

(2) *Terms of the contract.* The sale of natural gas at a special relief rate under this section shall be pursuant to a contract the terms of which specify:

(i) The portion of the sale price allocable over time to recovery of and return on investment costs; and

(ii) The time period, or estimated volumes of production, upon which this calculation was based.

(3) *Recordkeeping.* The first seller shall, for each project for which a rate is determined under this section, keep such records as are necessary to show the recovery of the capital investment component of the special relief rate including separate accounts describing:

(i) The depreciation expense attributable to the project;

(ii) The return on investment;

(iii) Taxes attributable to the project; and

(iv) Operating and maintenance expenses attributable to the project.

(4) *Termination of the capital recovery component.* No capital recovery component may be included as a part of a special relief rate for deliveries made after the time period specified in the contract for recovery of such component, or for deliveries in excess of 110 percent of the amount of natural gas estimated to be produced under subparagraph (2)(ii) of this paragraph, whichever is applicable.

(5) *Reports.* At the termination of the recovery of the capital investment component, the first seller shall report to the Commission the information contained in the accounts kept under subparagraph (3) of this paragraph.

§ 271.1005 Special relief rate for a well for which there is no planned investment.

(a) *Computation of rate.* The special relief rate for gas sold from a well for which there is no planned investment shall be the rate, in cents per unit of production (MMBtu's), under which it is predicted that the applicant will recover those operating expenses which are reasonably assigned or allocated to gas production from the well and an incentive allowance of 5 percent after allowance for Federal income tax. Such rate shall be determined for each calendar month by using the formula set forth in § 271.1004(c)(1). Paragraphs (2) through (4) (other than (4) (iii)) of § 271.1004(c) shall apply to such determination.

(b) *Incentive allowance.* An incentive allowance of 5 percent after allowing for Federal income tax shall be determined by multiplying the operating expense determined under this section (exclusive of regulatory expense and incentive allowance) by .05 and dividing the product by a divisor of one minus the tax rate applicable to the applicant, computed under § 271.1004(b)(2)(v).

§ 271.1006 Maximum special relief rate.

A special relief rate under this subpart may not exceed the national average refinery acquisition cost of imported crude oil, calculated and published pursuant to 10 CFR 211.67(i) by the Department of Energy in the Monthly Entitlements Notice, for the month in which the special relief application is filed (or, if greater, that for the month in which the gas is delivered), divided by 5.8.

Special Relief Rate Determination—Prepared by the Staff of the Federal Energy Regulatory Commission

The cost calculations presented herein demonstrate the methodology the staff would use to determine a special relief rate for a project in conformance with the regulations for special relief as set forth in Subpart J of Part 271. The methodology allocates costs between natural gas and liquids by the straight Btu method.

I. The Computation of the Two-Component Rate for New Investment Projects Other Than Small Projects

The Hypothetical Project

The hypothetical new investment project used in this example of the determination of a special relief rate consists of a new well drilled in a known gas field at an actual cost of $3,000,000, 70 percent of which represents intangible costs. The new well is successfully drilled and completed in a formation producing natural gas and liquids (condensate). It is estimated that the well will cost $12,000 to operate during the first year, have a productive life of 10 years, and produce for delivery and sale the gross quantities of natural gas (1030 Btu/cu. ft.) and condensate (5.448 MMBtu/Bbl) set forth in attached Schedule 1, Columns (b) and (c) subject to a 12.5 percent royalty interest.

Calculation of the Special Relief Rate

The following pages show the formulae and calculations which produce a starting special relief rate of $2.645 per MMBtu for the project. Schedules 1 through 3 show the derivation of the numbers used in the calculations. Schedule 4, the proof of the discounted cash flow method, shows that the discounted cash flow of the investment in and Federal income tax liability of the project is zero when the rate for this component, $2.606, is used.

This is a starting special relief rate related to an annualized gross gas production of 27,046 Mcf. The actual rates for deliveries during the period prior to and including the first full calendar month of production and subsequent calendar months would be determined by recomputing the component related to operating expense ($.039) in accordance with the procedure set forth in § 271.1004(c)(1) and adding the component related to investment ($2.606) which remains constant over the life of the project. An illustration of the calculation of subsequent rates appears on pages 8 and 9.

Determination of Rate Components

1. *The component reflecting a 16.5 percent true yield on investment*

This component is computed using the discounted cash flow methodology. The basic equation is:

Discounted Annual Revenue—(Discounted Investment + FIT) = 0 which becomes
R (Discounted Production) = Discounted Investment + FIT Tax Rate [R (Discounted Production)—Discounted Income Tax Deductions]—Discounted Investment Tax Credit.

For the hypothesis given, the values of the variables are:

Variable	Value	Source
R, which is the Rate	(1)	
Discounted Production	1,207,778	Sch. 2, Col. (e), line 13.
Discounted Investment	$2,980,457	Sch. 2, Col. (f), line 13.
FIT Tax Rate (percent)	46	Current Statutory Rate.
Discounted Income Tax Deductions.	$2,589,149	Sch. 3, Col. (g), line 12.
Discounted Investment Tax Credit.	$90,000	Sch. 3, Col. (h), line 12.

[1] Unknown.

The solution of the equation follows:

1,207,778 R = 2,980,457 + .46 (1,207,778 R—2,589,149)—90,000
652,200 R = 1,699,448
R = $2.60572 per MMBtu (rounds to $2.606)

2. *The component reflecting recovery of operating expenses.*

This component is computed using the estimated first-year's operating expense and net working interest production volume (in MMBtu). The equation is:

R = Operating Expense + Return on Working Capital + Regulatory Expense ÷ Net Working Interest Production

For the hypothesis given, the values of the variables are:

Variable	Value	Source
R, which is the Rate	(1)	Unknown
Operating Expense	$12,000	Hypothesis.
Return on Working Capital	$459	($12,000 × .125 × .165) (1—FIT Tax Rate) [62]Regulatory Expense
	$292	292,437 × $.001
FIT Tax Rate (percent)	46	Current Statutory Rate.
N.W.I. Production (MMBtu)	325,000	Sch. 1, Col. (h), line 1

(1) Unknown.

The solution of the equation follows:

$$R = \frac{12,000 + 459 + 292}{325,000}$$

R = $0.039234 per MMBtu (rounds to $0.039)

Schedule 1.—*Production Volumes*

Line No.	Year	Gross volumes		N.W.I. volumes		N.W.I. production unit		
		Gas (Mcf)	Liquids (Bbls)	Gas (Mcf)	Liquids Bbls)	Gas (MMBtu)	Liquids MMBtu)	Total (MMBtu)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1	324,548	6,818	283,978	5,966	292,497	32,503	325,000
2	2	299,587	6,293	262,139	5,506	270,003	29,997	300,000
3	3	274,616	5,769	240,289	5,048	247,498	27,502	275,000
4	4	249,653	5,244	218,446	4,589	224,999	25,001	250,000
5	5	224,688	4,720	196,602	4,130	202,500	22,500	225,000
6	6	199,722	4,195	174,757	3,671	180,000	20,000	200,000
7	7	149,787	3,147	131,064	2,754	134,996	15,004	150,000
8	8	124,828	2,622	109,225	2,294	112,502	12,498	125,000
9	9	99,858	2,098	87,376	1,836	89,997	10,003	100,000
10	10	49,929	1,049	43,688	918	44,999	5,001	50,000
11	Total	1,997,214	41,955	1,747,564	36,712	1,799,991	200,009	2,000,000

Column (b)—Estimated natural gas production.
Column (c)—Estimated liquids (condensate) production.
Column (d)—Column (b) times .875 net working interest.
Column (e)—Column (c) times .875 net working interest.
Column (f)—Column (d) times 1.03 MMBtu/Mcf.
Column (g)—Column (e) times 5.448 MMBtu/Bbl.
Column (h)—Sum of columns (f) and (g).

Schedule 2.—*Present Value of Production and Investment*

	Line No. and year	N.W.I. production (MMBtu)	Investment	Discount factors	Discounted production (MMBtu)	Discounted investment
	(a)	(b)	(c)	(d)	(e)	(f)
1	Start		$3,000,000	1.00000		$3,000,000
2	1	325,000		.92648	301,106	
3	2	300,000		.79526	238,578	
4	3	275,000		.68263	187,723	
5	4	250,000		.58595	146,488	
6	5	225,000		.50296	113,166	
7	6	200,000		.43173	86,346	
8	7	150,000		.37058	55,587	
9	8	125,000		.31809	39,761	
10	9	100,000		.27304	27,304	
11	10	50,000		.23437	11,719	
12	End		(90,000)	.21714		(19,543)
13	Total	2,000,000	2,910,000		1,207,778	2,980,457

Column (b)—Net working interest production from schedule 1, column (h).
Column (c)—Line 1: Total investment. Line 12: Net salvage value of tangible investment.
Column (d)—Lines 2-11 are mid-year factors at 16.5 percent. Line 12 is the end-of-year factor for year 10 at 16.5 percent.
Column (e)—Column (b) times Column (d).
Column (f)—Column (c) times Column (d).

Schedule 3.—*Present Value of Income Tax Deductions and Investment Tax Credit*

Line No and Year	Intangible Drilling costs	Depreciation	Total deductions	Investment tax credit	Discount factors	Discounted total deductions	Discounted investment tax credit
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Start	$2,100,000		$2,100,000	$90,000	1.00000	$2,100,000	$90,000
1		$131,625	131,625		.92648	121,948	
2		121,500	121,500		.73526	96,624	
3		111,375	111,375		.68263	76,028	
4		101,250	101,250		.58595	59,327	
5		91,125	91,125		.50296	45,832	
6		81,000	81,000		.43173	34,970	
7		60,750	60,750		.37056	22,513	
8		50,625	50,625		.31809	16,103	
9		40,500	40,500		.27304	11,058	
10		20,250	20,250		.23437	4,746	
11							
12 Total	2,100,000	810,000	2,910,000	90,000		2,569,149	90,000

Column (b)—70 percent of total investment of $3,000,000

Column (c)—Unit-of-production depreciation of net tangible investment ($810,000) **Net tangible investment is 30 percent of total investment of $3,000,000 less salvage value of $90,000.**

Column (d)—Sum of columns (b) and (c)

Column (e)—Investment tax credit is 10 percent times tangible investment of $900,000 **Tangible investment is 30 percent times total investment of $3,000,000**

Column (f)—From schedule 2, column (d)

Column (g)—Column (d) times column (f)

Column (h)—Column (e) times column (f)

Schedule 4.—*Discounted Cash Flow at $2.60572 per MMBtu*

Line No.	Year	N.W.I. production (MMBtu)	Revenue ($)	Investment ($)	Federal income tax ($)	Net cash flow ($)	Discount factor	Discounted cash flow ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Start			3,000,000	(1,056,000)	(1,944,000)	1.00000	(1,944,000)
2	1	325,000	846,859		329,008	517,851	.92648	479,778
3	2	300,000	781,716		303,699	478,017	.79526	380,148
4	3	275,000	716,573		278,391	438,182	.68263	299,116
5	4	250,000	651,430		253,083	398,347	.58595	233,411
6	5	225,000	586,287		227,775	358,512	.50298	180,317
7	6	200,000	521,144		202,466	318,678	.43173	137,582
8	7	150,000	390,858		151,850	239,008	.37058	88,572
9	8	125,000	325,715		126,541	199,174	.31809	63,355
10	9	100,000	260,572		101,233	159,339	.27304	43,506
11	10	50,000	130,286		50,617	79,669	.23437	18,672
12	End			(90,000)		90,000	.21714	19,543
13	Total	2,000,000	5,211,440	2,910,000	968,663	1,332,777		

Column (b)—Net working interest production from schedule 1, column (h).
Column (c)—Column (b) times $2.60572.
Column (d)—Total investment.
Column (e)—Line 1: [(Column (c) minus schedule 3, column (d)) times 46 percent] minus schedule 3, column (a). Lines 2-11: (column (c) minus schedule 3, column (d)) times 46 percent.
Column (f)—Column (c) less Columns (d) and (e).
Column (g)—From schedule 2, column (d).
Column (h)—Column (f) times column (g).

Illustrating the Calculation of Subsequent Rates

This illustration showing the calculation of subsequent rates once the starting rate has been determined is based on the following hypothesis:

1. Deliveries under the special relief rate start in mid-March.

2. Actual gross gas deliveries in April are 26,000 Mcf.

3. The published inflation adjustment for April is 1.00713.

4. Actual gross gas deliveries in May are 24,000 Mcf.

5. The published inflation adjustment for May is 1.00774.

(a) To calculate the rate for initial delivery period, mid-March through April, you simply:

1. Recalculate the component related to operating expense (Rc) using the formual set forth in § 271.1001(c)(1) and the following values:

Variable	Value	Source
Rp	$.039	The value of the component related to operating expense in the starting rate
I	1.00713	The published inflation adjustment as stated in the hypothesis.
Vp	27,046 Mcf	The annualized gross gas production related to the starting rate
Vr	26,000 Mcf	The actual gross gas deliveries for April as stated in the hypothesis

$$\text{New } Rc = \frac{.039 \times 1.00713 \times 27{,}046}{26{,}000}$$

$0.040858 per MMBtu (rounds to $0.041)

2. Add the component related to investment ($2.606).

This results in a rate of $2.647 for deliveries during the period mid-March through April.

(b) To calculate the rate for deliveries during May, you simply:

1. Recalculate the component related to operating expense (Rc) using the same formula and the following values:

Variable	Value	Source
Rp	$.041	The value of the component related to operating expense as determined above.
I	1.00774	The published inflation adjustment as stated in the hypothesis.
Vp	26,000 Mcf	The actual gross gas deliveries for April as stated in the hypothesis.
Vc	24,000 Mcf	The actual gross gas deliveries for May as stated in the hypothesis.

$$\text{Thus } Rc = \frac{.041 \times 1.00774 \times 26,000}{24,000}$$

= $0.044760 per MMBtu (rounds to $0.045)

2. Add the component related to investment ($2.606).

This results in a rate of $2.651 for deliveries during May.

(c) To calculate the rate for subsequent monthly periods, simply repeat the procedure in (b), above, using the values applicable to the variables.

II. The Computation of the Rate for a Well for Which There Is No Planned Investment.

The Hypothetical Project

The hypothetical well for which there is no planned investment used in this example of the determination of a special relief rate consists of a currently producing well whose revenues are insufficient to cover the out-of-pocket expense incurred in its operation. It is estimated that during the next year, an out-of-pocket expenditure of $48,000 will be required to produce gross volumes of 73,090 Mcf of 1020 Btu per cu. ft. gas (73,440 MMBtu) and 200 Bbls. of 5.448 MMBtu per Bbl. condensate (1090 MMBtu). This gross production volume of 74,530 MMBtu is subject to a 12.5 percent royalty interest.

Calculation of The Special Relief Rate

The following page shows the formula and calculation which produce a starting special relief rate of 5.805 per MMBtu. This is a starting special relief rate related to an annualized gross production of 6,000 Mcf. The actual rates for deliveries during the period prior to and including the first full calendar month of production and subsequent calendar months would be determined by recomputing this rate in accordance with the procedure set forth in § 271.1004(c)(1). An illustration of the calculation of subsequent rates appears on page 12.

Determination of Rate

The starting rate is computed using the estimated first-year's out-of-pocket expense and net working interest production volume (in MMBtu). The equation is:

$$R = \textit{Out-of pocket Expense} + \textit{Incentive Allowance} + \textit{Regulatory Expense} \div \textit{Net Working Interest Production}$$

For the hypothesis given, the values of the variables are:

Variable	Value	Source
R, which is the Rate	Unknown	
Out of pocket Expense	$48,000	Hypothesis
Incentive Allowance	$4,444	($48,000 × .05) ÷ (1—FIT Tax Rate)
Regulatory Expense	$64	73,440 × .875 × $.001
FIT Tax Rate	46%	Current Statutory Rate
Net Working Interest Production	65,214 MMBtu	74,530 × .875

The solution of the equation follows:

$$R = \frac{48,000 + 4,444 + 64}{65,214}$$

R = $.805 per MMBtu (rounds to $0.805)

Illustrating the Calculation of Subsequent Rates

This illustration showing the calculation of subsequent rates once the starting rate has been determined is based on the following hypothesis:

1. Deliveries under the special relief rate start in mid-March.

2. Actual gross gas deliveries in April are 5,500 Mcf.

3. The published inflation adjustment for April is 1.00713.

4. Actual gross gas deliveries in May are 5,000 Mcf.

5. The published inflation adjustment for May is 1.00774.

(a) To calculate the rate for the initial delivery period, mid-March through April, you simply recalculate the starting rate (Rc) using the formula set forth in § 271.1004(c)(1) and the following values:

Variable	Value	Source
Rp	$ 805	The starting rate
I	1.00713	The published inflation adjustment as stated in the hypothesis
Vp	6,000 Mcf	The annualized gross gas production related to the starting rate
Vc	5,500 Mcf	The actual gross gas deliveries for April as stated in the hypothesis

$$\text{Thus, Rc} = \frac{805 \times 1.00713 \times 6,000}{5,500}$$

$0.884444 per MMBtu (rounds to $0.884)

(b) To calculate the rate for deliveries during May, you simply recalculate the rate (Rc) using the same formula and the following values:

Variable	Value	Source
Rp	$ 884	The rate determined above
I	1.00774	The published inflation adjustment as stated in the hypothesis
Vp	5,500 Mcf	The actual gross gas deliveries for April as stated in the hypothesis
Vc	5,000 Mcf	The actual gross gas deliveries for May as stated in the hypothesis

$$\text{Thus, Rc} = \frac{884 \times 1.00774 \times 5,500}{5,500}$$

$0.979926 per MMBtu (rounds to $0.980)

(c) To calculate the rate for subsequent monthly periods, simply repeat the procedure in (b), above, using the values applicable to the variables.

¶ 32,066 Revision of Commission's Rules on Ex Parte and Separation of Functions

45 F. R. 36094 (May 29, 1980).

18 CFR Parts 1, 2 and 3c

[Docket No. RM80-60]

Revision of Commission's Rules on Ex Parte and Separation of Functions; Notice of Proposed Rulemaking

Issued: May 23, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission gives notice that it proposes to adopt new regulations controlling *ex parte* communications between persons outside the Commission and Commission decisionmakers, and new regulations controlling communications between decisionmakers and the Commission's advocacy or investigatory staff. The proposed rules will provide uniform *ex parte* and separation of functions rules for all trial-type proceedings at the Commission.

DATE: Written comments by June 27, 1980.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, reference Docket No. RM 80-60.

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8455.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (FERC or Commission) is proposing rules controlling *ex parte* communications in trial-type proceedings. It is further proposing rules concerning the separation of advocacy and decisionmaking functions in trial-type proceedings.

I. Background

The FERC has never formulated rules governing *ex parte* communications or separation of functions. Instead, pending promulgation of its own rules, the savings provision of the Department of Energy Organization Act (DOE Act) provides that the Federal Power Commission's (FPC) and the Interstate Commerce Commission's (ICC) *ex parte* and separation of functions rules continue to apply to proceedings that were previously subject to the jurisdiction of those Commissions.[1] The FPC rules vary from the ICC rules and neither are fully consistent with the applicable provisions of the Administrative Procedure Act (APA). In addition, other proceedings at the Commission are conducted under statutes that were not administered by the FPC or the ICC. The Commission has no specific *ex parte* or separation of functions rules applicable to these proceedings.

For these reasons, the Commission considers it necessary to promulgate a set of uniform rules on *ex parte* communications and separation of functions applicable to all trial-type proceedings conducted under the various statutes that it administers.[2] The rules proposed herein will accomplish this objective.

[1] Sections 401(f) and 705(a) of the DOE Act. The FPC's rules appear in 18 CFR 1.4 and 1.30(f). The ICC's rules appear in 49 CFR Part 1100, Appendix C.

[2] As part of its effort to arrive at a uniform set of proposed rules, the Commission has received advice and comment from various sources, including a report from the *Ex Parte* and Separation of Functions Subcommittee of the Commission's Advisory Committee on Revision of Rules of Practice and Procedure. The Subcommittee's report was submitted to the Commission on September 27, 1979. A copy of the report may be obtained from the Commission's Division of Public Information.

In addition, on August 25, 1978, the staff requested comments respecting revision of the rules of practice. Certain of the comments were directed to the *ex parte* rules. [Docket No. RM78-22].

In addition, the proposed rules will achieve a more fundamental and continuing objective of the Commission, that is, to insure those who practice before it that the decisionmaking process is both fair and equitable. One aspect of fairness in the decisionmaking process is "open" decisionmaking, a concept embodied in the Sunshine Act amendment to the APA.[3] In an effort to comply with the spirit of this provision, the Commission has already opened its deliberative meetings to the public in the majority of cases, including many cases which it is not required to open by the terms of that statute.

Another aspect of fairness concerns the integrity of the information gathering process that the Commission undertakes in a particular proceeding. In other words, the information gathering process should insure participants that the Commission will reach a decision in a proceeding based upon facts and arguments that have been publicly revealed. In statutorily required on-the-record proceedings, this result is insured by the dual provisions of the APA concerning *ex parte* communications (5 U.S.C. 557(d)) and separation of functions (5 U.S.C. 554(d)). As a matter of policy we propose *ex parte* and separation of functions rules patterned on the APA provisions to be applicable to all of our trial-type proceedings, including those to which the provisions of the APA do not apply.

II. Discussion

There is a close relationship between the proposed rules governing *ex parte* communications and those concerning separation of functions. Generally speaking, each constitutes a limitation on the access to or receipt of information that may be utilized in the decisionmaking process. The proposed *ex parte* rule constitutes a limitation on certain external communications. It proscribes off-the-record communications between decisionmakers and parties or interested persons outside the agency that are relevant to the merits of a pending trial-type proceeding. Similar communications between staff counsel or staff witnesses and third parties are not proscribed by the *ex parte* rule. Rather staff counsel and staff witnesses are restricted in their internal communications with decisionmakers by the proposed separation of functions rule. This rule would prohibit an agency investigator or advocate in a trial-type proceeding from participating in the decisionmaking process for that proceeding or another factually related trial-type proceeding or investigation.

A. Applicability of Proposed Rules

As stated earlier, both proposed rules will apply only to trial-type proceedings.[4] The term trial-type proceeding is defined in § 1.61(f). As proposed, § 1.61(f) sets forth five categories of proceedings which will be considered trial-type proceedings. These include proceedings conducted before the Commission under § 1.38 and § 1.40 of the present regulations to review remedial or adjustment orders issued by the Secretary of Energy under § 503(a) and § 504(a) of the DOE Act and proceedings conducted under § 1.40 of the present regulations pertaining to review of the grant or denial of adjustment requests under § 502(c) of the NGPA. The last two categories of trial-type proceedings include any proceeding which by Commission order has been set for hearing before an Administrative Law Judge: or any proceeding which by law, Commission rule, or order is required to be decided on the record after opportunity for Commission hearing.

B. Ex Parte Communications in Trial-type Proceedings

Section 1.63 of the proposed rules governs *ex parte* communications in trial-type proceedings. This section prohibits interested persons and decisional employees from making *ex*

[3] 5 U.S.C. § 52(b)

[4] The proposed rules do not apply to informal rulemaking proceedings. The Commission intends to consider whether to issue a notice of proposed rulemaking governing *ex parte* communications in informal rulemakings proceedings in the near future.

parte communications with respect to any trial-type proceeding while such proceeding is pending before the Commission. In addition, this section contains a disclosure requirement for decisional employees who make or receive communications in violation of the *ex parte* rule as well as a sanctions provision for knowing violations of the rule by parties.

Central to an understanding of § 1.63 are the definitions of interested person, decisional employee, *ex parte* communication and pending trial-type proceeding.

1. *Interested Person.* The definition of the term "interested person" is contained in § 1.61(a) of the proposed rule. The term is broadly defined and encompasses those persons defined as "parties" in § 1.61(b). Read in conjunction, § 1.61(a) and § 1.61(b) provide that the term "interested person" includes a party or any agent or other person acting on behalf of a party, as well as any person who has an economic or other identifiable interest in the outcome of a trial-type proceeding.

The broad nature of this definition is supported by the legislative history of the term "interested person" as it appears in Section 557(d) of the APA:

> The wording "interested persons" is intended to be a wide, inclusive term covering any individual or other person with an interest in the agency proceeding that is greater than the general interest the public as a whole may have. The interest need not be monetary, nor need a person to be a party to, or intervenor in, the agency proceeding to come under this section. The term, includes, but is not limited to, parties, competitors, public officials, and nonprofit or public interest organizations, and associations with a special interest in the matter regulated. As used in this section, "person" has the same meaning as elsewhere in the Administrative Procedure Act.[5]

There are certain exclusions contained in the proposed definitions of interested person and party. First, a federal agency which is not a party to a trial-type proceeding is excluded from the definition of interested person. This exclusion is derived from the above-quoted legislative history:

> • • • As used in this section, "person" has the same meaning as elsewhere in the Administrative Procedure Act.[6]

Section 551(2) of the APA defines "person" to include "an individual, partnership, corporation, association, or public or private organization *other than an agency.*" (emphasis supplied) [7]

The Commission believes that there is a sound policy basis for generally excluding federal agencies from the category of interested persons. A cohesive government policy on any issue can only be derived and sustained by a free flow of information between the various federal agencies charged with formulating and implementing various aspects of that policy. This is to be distinguished from the situation where a federal agency becomes a party to a trial-type proceeding or makes a communication on behalf of a party to a trial-type proceeding. In the latter situation, where the agency acts as an advocate and in an adversary capacity, the communications would properly be characterized as *ex parte.* The proposed definition of "party" contained in § 1.61(b) insures that this result will be reached by encompassing those persons, including for example federal agencies, who act as agent for or on behalf of a party to a trial-type proceeding.

In certain cases, the Commission believes that the policy underlying this exclusion may be equally applicable to communications between the FERC and state agencies which are not parties to a pending trial-type proceeding. The APA does not appear to provide a basis for this exclusion. However, the Commission seeks comment on the legal basis, if any, for permitting such an exclusion for state agencies.

The second exclusion is contained in the definition of "party." As defined, the term "party" does not include the staff of the Commission. The *ex parte*

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[5] S. Rep. No. 94-354, 94th Cong., 1st sess. 36 (1975); H. Rep. No. 94-880 Part 2, 94th Cong., 2d sess. 19, (1976).

[6] Id.

[7] 5 U.S.C. § 551(2)

prohibitions contained in the proposed rule are only aimed at interested persons *outside* the agency. The prohibition on intra-agency communications is contained in the proposed rule on separations of functions discussed below.

2. *Decisional Employee.* The definition of "decisional employee" is contained in § 1.61(c) of the proposed rule. Under this definition all employees of the Commission are decisional employees unless they are staff advocates, staff investigators or are otherwise so designated under § 1.62(b) which is discussed below. The terms staff advocate and staff investigator are defined in § 1.61(d) and § 1.61(e), respectively. Staff advocate includes any person who is assigned to or who makes an appearance as staff counsel or staff witness in a trial-type proceeding. Staff investigator includes any person designated under § 1b.5 as an investigating officer in a formal investigation.

In addition, under § 1.62(b) of the proposed rule the Chairman may designate any employee (or class thereof) as a decisional employee, staff advocate or staff investigator. The proposed rule provides that any designation by the Chairman will be available to the public in the Office of the Secretary.

3. *Ex Parte* Communication. As discussed above, the proposed rule prohibits decisional employees and interested persons from making *ex parte* communications. The term *ex parte* communication is defined in § 1.63(d) of the proposed rule and includes any oral or written communication not on the public record which is relevant to the merits of a proceeding and with respect to which reasonable prior notice to all parties has not been given.

The term relevant to the merits is not defined in the proposed rule. However, § 1.62(a) of the proposed rule sets forth certain classes of communications that are specifically excluded from being relevant to the merits.

Section 1.62(a)(1) provides that a communication is not relevant to the merits of a proceeding if it is a status report or request for a status report; relates to a matter of procedure or is made in the course of another proceeding being conducted before the Commission and is on the public record of that proceeding.

Certain other exclusions are contained in § 1.62(a)(2) of the proposed rule. The exclusions contained in this paragraph apply to both the *ex parte* rule set forth in § 1.63 and the separations of functions rule set forth in § 1.64. Communications which are specifically authorized by law are excluded. For instance, communications that take place pursuant to consultation provisions contained in certain of the statutes that the Commission administers would fall within this category. Second, communications which would otherwise be prohibited by the regulations can be made if all parties to the proceeding agree that the communication can take place. Finally, any communication which relates to the conduct of military or foreign affairs is excluded, if the Chairman determines that disclosure of the communication would be inimical to the military or foreign affairs functions of the United States.*

4. *Pendency of Proceeding.* The prohibition against *ex parte* communications contained in § 1.63 of the proposed rule applies only while a trial-type proceeding is pending before the Commission. Section 1.63(d)(2) of the proposed rule sets forth the time period during which a proceeding will be considered to be pending before the Commission.

Section 1.63(d)(2)(i) of the proposed rule defines the earliest time at which the *ex parte* prohibition will apply. It will apply at the earliest of: the time that a proceeding is noticed for hearing; the time when an opposing protest or intervention is first filed or a response in opposition to a complaint is filed; the time at which a petition for review is

*See, 5 U.S.C. § 553(a)(1) and § 554(a)(4).

filed under § 1.38(d) or § 1.40(d); or it will apply to a communicator who reasonably believes that a proceeding will be noticed for hearing. In the latter situation the prohibition applies as soon as the communicator obtains such knowledge, but not before the proceeding is docketed. The Commission specifically requests comment on this aspect of the proposed rule.

Section 1.63(d)(2)(ii) of the proposed rule defines the time when a proceeding will no longer be subject to the *ex parte* rule. The concept embodied in § 1.63(d)(2)(ii) of the proposed rule is one of finality. Therefore, as proposed, the *ex parte* prohibitions of § 1.63 will terminate at the earliest of: the time when a decision becomes final agency action for purposes of judicial review; at the expiration of the time for filing applications for rehearings, if rehearing lies and no applications for rehearing have been filed; or ten days after the expiration of time for filing exceptions to an intermediate decision, if no exceptions have been filed.

5. *Remedies.* As described above, the proposed *ex parte* rule prohibits interested persons and decisional employees from making *ex parte* communications with respect to any trial-type proceeding while such proceeding is pending before the Commission. The underlying purpose of the proposed rule is to maintain the integrity of the decisionmaking process by insuring participants that the only facts and arguments that will be utilized in the process are those that have been publicly made on the record of a particular proceeding.

The first step toward achieving this result is to discourage and prohibit interested persons from making off-the-record, *ex parte* communications to decisional employees. The second step is to provide a mechanism whereby participants to a proceeding can obtain knowledge of the nature and contents of an *ex parte* communication should it occur.

Section 1.63(c) of the proposed rule set forth the remedies for noncompliance with the *ex parte* rule. Under § 1.63(c)(1) of the proposed rule, decisional employees are directed to decline the receipt of any communication which that employee has reason to believe is prohibited by the *ex parte* rule and to inform the communicator that the matter is pending before the Commission.

Under § 1.63(c)(2)(i) of the proposed rule if a decisional employee makes or receives an *ex parte* communication it must be delivered to the Secretary of the Commission within 48 hours after that person first had reason to believe that the communication was prohibited under § 1.63. If the communication was written it should be delivered directly to the Secretary. If the communication was made orally, a statement setting forth the substance of the communication must first be prepared and then delivered to the Secretary.

Section 1.63(c)(2)(ii) of the proposed rule requires the Secretary to place any such statements or communications in the public file. This public file is to be associated with the particular proceeding to which the communication relates but is to be separate from the record upon which the Commission will rely in reaching its decision in the proceeding. In addition, the Secretary must mail a copy of the statement or communication to each person on the official service list for the proceeding.

The Commission believes that the disclosure requirement of the proposed rule will serve two purposes. First, it should provide a sufficient disincentive to those persons who would contemplate the use of an *ex parte* communication to achieve a particular result in a pending proceeding. Second, the Commission recognizes that there may be circumstances where an *ex parte* communication may be made inadvertently. In those situations, notice to all participants in the proceeding of the nature and contents of the communication should be an adequate remedy.

However, the Commission realizes that a party to a proceeding may knowingly make or cause another to make an *ex parte* communication to a decisional employee. Depending on the

circumstances, the disclosure remedy may not be adequate to either protect the interests of other participants to the proceeding or to discourage a calculated course of conduct.

Therefore, under § 1.63(d)(3) of the proposed rule a participant may apply to the Commission or a presiding officer may certify to the Commission for its determination the question of whether a party has knowingly made a communication in violation of the *ex parte* rule. The proposed rule provides that if the Commission determines that such a violation did occur then the Commission may, to the extent consistent with the interests of justice and the policy of the underlying statutes, require the party to show cause why his claim or interest in the proceeding should not be dismissed, denied, disregarded, or otherwise adversely affected.

C. Separation of Functions

Section 1.64 of the proposed rule concerns the separation of advocacy and decisionmaking functions in trial-type proceedings. Generally, this section prohibits certain employees of the Commission from advising certain decisional employees respecting a pending or factually related trial-type proceeding.

As previously discussed, the proposed separation of functions rule constitutes an internal limitation on the information which may be gathered and used in a particular proceeding. Since the proposed rule limits the Commission's accessibility to staff persons and therefore, limits its access to information that would otherwise be available to it, the rule has been narrowly drawn, both as to the class of persons who will be considered decisionmakers and the class of employees who will be prohibited from giving advice to those decisionmakers respecting a particular trial-type proceeding.

Section 1.64(a) of the proposed rule specifies which persons will be considered decisionmakers for all trial-type proceedings. These include: the Commission, any Commissioner or Commission's assistant, the Oil Pipeline Board or member thereof, any member of the Office of Opinions and Review and the Administrative Law Judge who presided at the trial-type proceeding.

Under the proposed rule, the class of employees prohibited from advising those decisionmakers will vary from case to case. For instance, under proposed § 1.64(a)(1), if the employee was the staff advocate (as defined in § 1.61(a)) in the trial-type proceeding or was a staff advocate in a factually related trial-type proceeding then he would be prohibited from advising on the trial-type proceeding pending decision. Similarly, § 1.62(a)(2) of the proposed rule provides that an employee who was designated as a staff investigator in a formal investigation under § 1b.5 of the present regulations would be prohibited from advising on the pending trial-type proceeding if the trial-type proceeding was factually related to the formal investigation.

The proposed rule on separation of functions also sets forth definitions of the terms "factually related" and "advise". Under proposed § 1.64(b)(1)(i), a trial-type proceeding is factually related to another trial-type proceeding if there is a substantial identity of facts which are material to both proceedings. In addition, under § 1.64(b)(1)(ii) of the proposed rule, a trial-type proceeding is factually related to a formal investigation if the same conduct of a person is the subject of both proceedings. The term "advise" is defined in § 1.64(b)(2) of the proposed rule to mean giving advice as to the findings, conclusions, or decision respecting a proceeding, other than in the role of staff counsel or staff witness in a public proceeding.

D. Other Provisions

Section 1.62 contains three additional provisions that warrant discussion. These provisions, which apply to both the *ex parte* rule in § 1.63 and the separation of functions rule in § 1.64,

concern: phased or segmented proceedings; waiver of the regulations; and opinions of the General Counsel.

In the past, certain proceedings at the Commission have been phased or segmented in such a way that one phase of the proceeding has been conducted as a trial-type, on-the-record proceeding while another phase has been conducted as an informal rulemaking proceedings. Under section 1.62(e) of the proposed rule, the Commission may by rule or order provide that each phase or segment of the proceeding will constitute a separate proceeding for purposes of the *ex parte* and separation of functions rules.

Section 1.62(c) of the proposed rules contains a general waiver provision, under which the Commission may, to the extent permitted by law, waive any provision of the proposed rules as it may apply to all or part of a proceeding. As discussed earlier, the Commission has chosen, as a matter of policy, to propose rules governing *ex parte* communications and separation of functions which go beyond the applicable APA provisions. The Commission added § 1.62(c) to the rules because it recognizes that certain situations may arise where the application of these more stringent provisions may unduly restrict its ability to render an informed decision.

Finally, § 1.62(d) of the proposed rule concerns opinions of the General Counsel. Under this paragraph any person may apply to the Office of the General Counsel for an opinion as to whether any provision of the proposed rules applies to a communication or class of communications.

III. Comment Procedure

Interested persons may participate in this proposed rulemaking by submitting written comments. The comments may include any data, views or arguments that the commenter believes are relevant. Legal and policy considerations should be given in support of any recommendations concerning the proposed rules.

An original and 14 conformed copies of the comments should be submitted to the Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before June 27, 1980. Comments should identify the notice (Docket RM80–60) and should indicate the name, title, mailing address and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

(Federal Power Act, *as amended*, 16 U.S.C. 792 *et seq.*; Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Interstate Commerce Act, as amended, 47 U.S.C. 1 *et seq*; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601–2645; Department of Energy Organization Act, Pub. L. No. 95–91, 91 Stat. 565, *et seq.*, E.O. 12009, 3 CFR 142 (1978); Administrative Procedure Act, 5 U.S.C. §§ 500 *et seq.*)

In consideration of the foregoing, the Commission is proposing to amend Parts 1, 2 and 3 of Chapter 1, Title 18 Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 1—RULES OF PRACTICE AND PROCEDURE

1. Chapter I is amended in the table of contents to Part 1 and in the text of the regulations by inserting the title "Subpart A—General rules" before § 1.1 and by adding the following to the end thereof:

* * * * *

Subpart B—Ex Parte and Separation of Functions Rules

Sec.

1.61 Definitions.
1.62 General Provisions.
1.63 Ex parte communications in trial-type proceedings.
1.64 Separation of functions.

Authority: Federal Power Act, as amended, 16 U.S.C. 792 et seq.; Natural Gas Act, as amended, 15 U.S.C. 717 et seq.; Interstate Commerce Act, as amended, 47 U.S.C. 1 et seq.; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; Department of Energy Organization Act, Pub. L. 95–91, 91 Stat. 565, et seq., E.O. 12009, 3 CFR 142 (1978); Administrative Procedure Act, 5 U.S.C. 500 et seq.

Subpart B—Ex Parte and Separation of Functions Rules

§ 1.61 Definitions.

For purposes of this subpart:

(a) The term "interested person" with respect to a proceeding means a person who has an economic or other identifiable interest in the outcome of such proceeding. Such term includes any party to such proceeding, but does not include a Federal agency which is not a party to such proceeding unless the Commission otherwise provides by rule or order.

(b) The term "party" includes an applicant, respondent, petitioner, declarant, complainant, defendant and intervenor in a trial-type proceeding, and any agent or other person acting on behalf of any of the above. Such term does not include the staff of the Commission.

(c) The term "decisional employee" with respect to a proceeding means any member of the Commission, any Commission presiding officer and any employee of the Commission other than (i) a staff advocate, or a staff investigator in such a proceeding, or (ii) any other person designated under § 1.62(b) as not being a decisional employee.

(d) "Staff advocate" means any person who is assigned or makes an appearance as staff counsel or staff witness in a trial-type proceeding, and any other person designated under § 1.62(b) as a staff advocate with respect to such proceeding.

(e) "Staff investigator" means a person designated under § 1b.5 as an Investigating Officer or otherwise designated under § 1.62(b) as a staff investigator.

(f) The term "trial-type proceeding" means a proceeding of the Commission:

(1) to review a remedial order under § 1.38,

(2) to review an adjustment request denial under § 1.40,

(3) to review, under § 1.40, the grant or denial of an adjustment under § 1.41(i), or

(4) which by Commission order has been set for a hearing before an ALJ, or

(5) which by law or Commission rule or order is required to be decided on the record after opportunity for Commission hearing and in which protest or intervention in opposition or response in opposition to a complaint is filed.

(g) For definitions of "person" and "Presiding Officer", see §§ 1.1(f)(1) and 1.1(b)(6).

§ 1.62 General provisions.

(a) *Exclusions.* (1) *Not relevant to merits.* For purposes of this subpart, the term "communication relevant to the merits" does not include a communication with respect to proceeding if such communication:

(i) is a status report or request for a status report,

(ii) relates to a matter of procedure,

(iii) is made in the course of another proceeding of the Commission to which it primarily relates, and is on the public record.

(2) *Other exclusions.* This subpart does not apply to any communication:

(i) which is specifically authorized by law;

(ii) which is one all parties to a proceeding agree may be made without regard to the applicable provisions of this part, in the case of a trial-type proceeding; or

(iii) which relates to the conduct of military or foreign affairs functions, the disclosure of which the Chairman determines would be inimical to the military or foreign affairs functions of the United States.

(b) *Designation of employees.* Any employee (or class of employees) may be designated for purposes of § 1.61(c), (d) or (e) by the Chairman, or in a manner prescribed by the Chairman. Any such designation shall be available

to the public in the Office of the Secretary.

(c) *Waiver.* The Commission may, by rule or by order, waive or modify any provision of this subpart as it applies to all or part of a proceeding (or class of proceedings), to the extent permitted by law.

(d) *Office of General Counsel opinion.* Any employee of the Commission or person may apply to the Office of General Counsel for an opinion as to whether any provision of this subpart is applicable to a communication or class of communications.

(e) *Phased or segmented proceedings.* If a proceeding is phased or segmented so that one or more parts of the proceeding constitute informal rulemaking and one or more parts constitute trial-type proceedings, the Commission may by order provide that each phase or segment shall constitute a separate proceeding for purposes of this subpart.

§ 1.63 Ex parte communications in trial-type proceedings.

(a) *Applicability.* This section applies to any trial-type proceeding.

(b) *Prohibited communications.* (1) No interested person may, with respect to any trial-type proceeding make (or knowingly cause to be made) to any decisional employee any *ex parte* communication while such proceeding is pending before the Commission.

(2) No decisional employee may, with respect to any trial-type proceeding, make (or knowingly cause to be made to any interested person any *ex parte* communication while such proceeding is pending before the Commission.

(c) *Remedies for noncompliance.*—(1) *Declining to receive and consider communications.* A decisional employee who receives an oral offer of a communication which he has reason to believe is prohibited by paragraph (b)(1) shall decline to listen to such communication, shall state that the matter is pending before the Commission and shall advise the communicator that the communication will not be considered.

(2)(i) *Disclosure.* A decisional employee who makes or receives a communication respecting such proceeding, which is prohibited by paragraph (b) shall, within 48 hours after he first has reason to believe that such communication is prohibited:

(A) prepare and deliver to the Secretary a statement setting forth the substance of the communication if it is in oral form; or

(B) deliver it to the Secretary if it is in written form.

(ii) The Secretary shall place any communications and statements received by him under clause (i) in public files associated with the proceeding, but separate from the record upon which the Commission may rely in reaching its decision. The Secretary shall mail to each person on the official service list of the proceeding a copy of any matter delivered under clause (i).

(3) *Knowing violations by parties.* If on the application of a participant or upon the presiding officer's certification, the Commission determines that the communication was knowingly made (or caused to be made) by a party acting in violation of this section, the Commission may, to the extent consistent with the interests of justice and the policy of the underlying statutes, require the party to show cause why his claim or interest in the proceeding should not be dismissed, denied, disregarded, or otherwise adversely affected on account of such violation.

(d) *Definitions.* For purposes of this section:

(1) "*Ex parte* communication" means an oral or written communication not on the public record which is relevant to the merits of a proceeding and with respect to which reasonable prior notice to all parties has not been given.

(2) A proceeding is pending before the Commission during the period which:

(i) Begins at the earlier of:

(A) When it is noticed for hearing; or

(B) With respect to a communicator who reasonably believes it will be noticed for hearing, when he obtains such knowledge (but not before the proceeding is docketed); or

(C) When a protest, intervention in opposition or response in opposition to a complaint, is first filed; or

(D) When a petition for review is filed in accordance with § 1.38(d) or § 1.40(d); and

(ii) Ends at the earliest of:

(A) The time when the decision becomes a final agency action for purposes of judicial review; or

(B) In cases where rehearing lies and no applications for rehearing have been filed at the expiration of the time for filing such applications; or

(C) Ten days after the expiration of time for filing exceptions to an intermediate decision if no exceptions are filed.

§ 1.64 Separation of functions.

(a) *General rule.* No employee may advise the Commission, any Commissioner (or assistant thereto), the Oil Pipeline Board (or member thereof), member of the Office of Opinions and Review, or presiding Administrative Law Judge, respecting any trial-type proceeding, if:

(1) such employee was a staff advocate in such trial-type proceeding or in a factually related trial-type proceeding or

(2) such employee was a staff investigator in a factually-related formal investigation under § 1b.5.

(b) *Definitions.* For purposes of this section:

(1) *Factually related.* (i) A trial-type proceeding is factually related to another trial-type proceeding if there is substantial identity of facts which are material to both proceedings.

(ii) A trial-type proceeding is factually related to a formal investigation if the same conduct of a person is the subject of both proceedings.

(2) *Advise.* The term "advise" means advise as to the findings, conclusions, or decision respecting a proceeding (other than as witness or counsel in public proceedings).

PART 2—GENERAL POLICY AND INTERPRETATIONS

PART 3c—STANDARDS OF CONDUCT

§§ 1.4, 1.27, 1.30, 1.38, 1.40, 2.100, 3c.6, 3c.112, 3c.206 [Amended]

2. Chapter 1 is further amended in the following sections: In § 1.4 by deleting paragraph (d); in § 1.27 by deleting the second sentence of paragraph (c); in § 1.30 by deleting paragraph (f); in § 1.38(o) by deleting "§ 1.4(d) of this subpart" and inserting in lieu thereof "§ 1.63 of this part"; in § 1.40(k)(1) by deleting "§ 1.4(d) of this subpart" and inserting in lieu thereof "§ 1.63"; in § 2.100(d) by deleting "18 CFR § 1.4(d)" and inserting in lieu thereof "§ 1.63 of this subchapter"; in § 3c.6(f) by deleting "Section 1.4(d)" and inserting in lieu thereof "Section 1.63 of this subchapter"; in § 3c.112(f)(3) by deleting "Section 1.4(d)" and inserting in lieu thereof "Section 1.63 of this subchapter"; and in § 3c.206(f)(3) by deleting "Section 1.4(d)" and inserting in lieu thereof "Section 1.63 of this subchapter".

¶ 32,067 Proposed Rulemaking to Revise Annual Report for Public Utilities and Licensees (Class C and Class D): Form No. 1-F, and Annual Report for Natural Gas Companies (Class C and Class D): Form No. 2-A

45 F. R. 36428 (May 30, 1980).

18 CFR Parts 141 and 260

[Docket No. RM80-59]

Proposed Rulemaking To Revise Annual Report for Public Utilities and Licensees (Class C and Class D): Form No. 1-F, and Annual Report for Natural Gas Companies (Class C and Class D): Form No. 2-A

Issued May 23, 1980

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it proposes to revise its annual reports, Form No. 1-F, "Annual Report for Utilities and Licensees (Class C and Class D)" (18 CFR 141.2), and Form No. 2-A, "Annual Report for Natural Gas Companies (Class C and Class D)" (18 CFR 260.2). The proposed amendments would eliminate certain data elements which the Commission no longer needs to carry out its regulatory functions. The proposed changes are a product of the Commission's ongoing effort to eliminate unnecessary reporting burdens.

DATE: Comments are due by July 22, 1980.

ADDRESS: Comments to this Notice should be addressed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80-59.

FOR FURTHER INFORMATION CONTACT:

James Kitchen, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 3408N, Washington, D.C. 20426 (202) 357-9212.

Elaine M. Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 3405N, Washington, D.C. 20426 (202) 357-9190.

Revisions of Form No. 1-F, Annual Report for Public Utilities and Licensees (Class C and Class D and Form No. 2-A, Annual Report for Natural Gas Companies (Class C and Class D).

I. Background

The Federal Energy Regulatory Commission (Commission) is engaged in an ongoing effort to eliminate unnecessary reporting burdens. This rulemaking, to amend Form No. 1-F, "Annual Report for Public Utilities and Licensees (Class C and Class D)", and Form No. 2-A, "Annual Report for Natural Gas Companies (Class C and Class D)" [1] is part of that effort and reflects an evaluation of data needed by the Commission to carry out its regulatory functions. The proposed revisions for the Form Nos. 1-F and 2-A should result in a significant reduction in respondent burden.

Form No. 1-F collects information annually from privately owned electric utilities. The data primarily include Balance Sheet, Income Statement, and related items.

Form No. 2-A collects information annually from natural gas companies. The data primarily include natural gas operating revenues, expenses, and sales.

The Commission has reviewed Form Nos. 1-F and 2-A in light of its regulatory responsibilities, and has determined that it no longer needs certain elements of the data collected.

[1] A Class C electric utility or natural gas company is one having annual electric or gas operating revenues of $150,000 or more but less than $1,000,000. A Class D electric utility or natural gas company is one having annual electric or gas operating revenues of $25,000 or more but less than $150,000.

The proposed deletions would cause an estimated 63 percent reduction in the reporting burden for Form No. 1–F and an estimated 28 percent reduction for Form No. 2–A.

The Energy Information Administration (EIA), however, may decide on behalf of itself or other sponsors within the Department of Energy to continue the collection of some data proposed for deletion herein. If the EIA should make such a determination, the Commission would issue a Final Rule based on this Notice with a delayed effective date. This would provide EIA (or any other potentially interested agency) a period of time in which to justify the need for the data and receive the approval for collection of such data under the agency's own authority.

II. Summary of Revisions

The following is a brief description of the proposed revisions to each of the forms:

a. *Form No. 1–F*[2]

The Commission proposes in this rulemaking to eliminate 509 of the 811 data items now prescribed on Form No. 1–F (approximately 63 percent). Of the 509 items, 448 would be deleted by elimination of reporting requirements for the following schedules:

Schedule:	Page no.
Security Holders and Voting Powers	3
Officers and Directors	3
Accumulated Provision for Depreciation and Amortization of Utility Plant	6
Capitol Stock	6
Long-Term Debt	6
Electric Sales Data for the Year	7
Sales of Electricity for Resale	7
Electric Operation and Maintenance Expenses	7
Purchased Power	11
Utility Plant	11
Generating Station Statistics	12
Transmission Line Statistics	12
Transmission Lines Added During Year	12
Investment Tax Credits Generated and Utilized	13
Accumulated Deferred Investment Tax Credits (Account 255)	14
Expenditures for Certain Civic, Political, and Related Activities	15

The remaining 61 data items would be eliminated by deleting the "Increase and (Decrease)" data requirements of the Comparative Balance Sheet (columns (d) and (h), schedule pages 4 and 5, respectively).

The data which would be retained are currently reported on the following schedules:

Schedule:	Page no.
General Information	[3] 1
Comparative Balance Sheet (columns a, b, c, e, f, g)	4 (a, b, c) 5 (e, f, g)
Statement of Income for the Year	8, 9
Statement of Retained Earnings	10
Attestation	

[3] A change would be made on page 1 to require that the completed form shall be sent to EIA rather than to the Commission.

b. *Form No. 2-A*[4]

The Commission proposes to eliminate 254 of the 907 data itmes now prescribed on Form No. 2–A (approximately 28 percent). These reductions in reporting burdens would be accomplished by: (1) deletion of the Prinicpal Business and Address column of the "Officers and Directors Schedule" (column c, schedule page 3); (2) elimination of the "Increase and (Decrease)" data requirement from the Balance Sheet (columns (d) and (h), schedule pages 4 and 5, respectively); and (3) deletion of the following schedules:

Schedule:	Page no.
Investment Tax Credits Generated and Utilized	15
Accumulated Deferred Investment Tax Credits (Account 255)	16
Expenditures for Certain Civic, Political and Related Activities	17
Service Interruptions Occurring on the Pipeline System	18

Data which would be retained on Form No. 2–A are currently reported on the following schedules:

Schedule:	Page no.
General Information	[3] 1
Security Holders and Voting Powers	3
Officers and Directors (columns a, b, d)	3
Comparative Balance Sheet (columns a, b, c, e, f, g)	4 (a, b, c) 5 (e, f, g)
Accumulated Provisions for Depreciation, Depletion and Amortization of Utility Plant	6
Capital Stock	6
Long-Term Debt	6
Gas Sales Data for the Year	7
Gas Operation and Maintenance Expenses	7
Statement of Income for the Year	8, 9
Statement of Retained Earnings	10
Sales for Resale—Natural Gas (Account	

[2] Attachment A

[3] Attachment B.

Schedule	Page no
483)	11
Gas Purchases (Accounts 730, 731—Class C)	12
Utility Plant Natural Gas Companies	13
Gas Account—Natural Gas	14
General Information Concerning Plant and Operations	14
Alter" on	—

[1]A change would be made on page 1 to require that the completed form shall be sent to EIA rather than to the Commission.

[2]A change would be made to the instructions in the Officers and Directors Schedule whereby the requirement to list the addresses of the officers and directors would be deleted and a requirement to "(list officers first) whose salaries are $50,000 or more", would be added.

III. Comment Procedures

The Commission invites interested persons to submit written comments on this proposal. Copies of all comments will be furnished to the EIA for its use. The Commission specifically requests that the comments address the following questions:

1. Do the proposed revisions or eliminations of required data affect any Commission or State regulatory functions?

2. Is there any reason for continued collection of the data for the purposes of another Federal agency? Suggestions for the continued collection of data which has been proposed for elimination from the present Form Nos. 1–F and 2–A should identify the proper agency and the purpose for collection of the data.

Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should refer to Docket No. RM80–59. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, July 22, 1980, will be considered by the Commission prior to promulgation of final regulations. Pursuant to 44 U.S.C. 3501–3511, these proposed revisions will be considered by the Office of Management and Budget for lultimate clearance. Interested persons wishing to have their comments considered during the clearance process should submit copies of their comments to the Commission and to the Clearance Office of Regulatory Policy and Report Management Divisions, Office of Management Division, Office of Management and Budget, Washington, D.C. 20503. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection during regular business hours in the Commission's Division of Public Information, Room 1000, 825 N. Capitol Street, N.E., Washington, D.C. 20426.

[Natural Gas Act, as amended, 15 U.S.C. 717–717w; Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267 (September 15, 1977)]

In consideration of the foregoing, the Commission proposes to revise Form No. 1–F, "Annual Report for Public Utilities and Licensees (Class C and Class D)," prescribed by Section 141.2, Chapter 1, Title 18 of the Code of Federal Regulations and Form No. 2–A, "Annual Report for Natural Gas Companies (Class C and Class D)," prescribed by § 260.2, Chapter I, Title 18 of the Code of Federal Regulations as set forth in Attachments A and B.

In addition, in consideration of the foregoing, the Commission proposes to amend Parts 141 and Part 260 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below. By direction of the Commission.

Kenneth T. Plumb,

Secretary.

PART 141—STATEMENTS AND REPORTS (SCHEDULES)

1. In § 141.2, the section heading and paragraph (c) are revised to read as follows:

§ 141.2 FERC Form No. 1–F, Annual Report for Public Utilities and Licensees (Class C and Class D).

* * * * *

(c) This annual report contains the following schedules:

Identification.
General Instructions.
General Information.
Comparative Balance Sheet.
Statement of Income for the Year.
Statement of Retained Earnings.
Attestation.

* * * * *

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

2. In § 260.2 the section heading and paragraph (c) are revised to read as follows:

§ 260.2 FERC Form No. 2-A, Annual Report for Natural Gas Companies. (Class C and Class D)

* * * * *

(c) This annual report contains the following schedules:

Identification.
General Instructions.
General Information.
Security Holders and Voting Powers.
Officers and Directors.
Comparative Balance Sheet.
Accumulated Provisions for Depreciation, Depletion and Amortization of Utility Plant.
Capital Stock.
Long-Term Debt.
Gas Sales Data for the Year.
Gas Operation and Maintenance Expenses.
Statement of Income for the Year.
Statement of Retained Earnings.
Sales for Resale—Natural Gas.
Gas Purchases.
Utility Plant Natural Gas Companies.
Gas Account—Natural Gas.
General Information Concerning Plant and Operations.
Attestation.

* * * * *

¶ 32,068 Exemption of Mechanical Cogeneration Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act

45 F. R. 38080 (June 6, 1980).

18 CFR Part 282

[Docket No. RM80-62]

Exemption of Mechanical Cogeneration Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act

Issued May 30, 1980

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rule.

SUMMARY: The Federal Energy Regulatory Commission hereby issues proposed rules under section 206(d) of the Natural Gas Policy Act of 1978 (NGPA) for the exemption of mechanical cogeneration facilities from incremental pricing provisions of Title II of the NGPA. The cogeneration incentive provided through the exemption from incremental pricing is intended to significantly promote energy conservation bo cogeneration facilities.

DATES: Requests to participate in the hearing: June 20, 1980, by 4:30 p.m. Copies of Statement at hearing: June 25, 1980, by 4:00 p.m. Written comments on proposed rule: June 30, 1980. Public hearing: July 1, 1980, 10:00 a.m.

ADDRESSES: Written submissions: Office of the Secretary; Federal Energy Regulatory Commission, 825 N. Capitol St. NE, Washington, D.C. 20426 (Reference Docket No. RM80-62); The public hearing will be held at the same address in a room to be announced.

FOR FURTHER INFORMATION CONTACT: Clarence Burris, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8106-A, 825 N. Capitol St, NE, Washington, DC 20426 (202) 357-8161.

I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) requires that the natural gas used in certain industrial facilities be subject to incremental pricing by means of surcharges. Section 206 of the NGPA establishes certain exemptions from these incremental pricing surcharges. Section 206(c)(3) provides that incremental pricing shall not apply:

> (3) to the extent provided by the Commission by rule, any qualifying cogenerator (as defined in section 3(18)(B) of the Federal Power Act, as amended by the Public Utility Regulatory Policies Act of 1978) (PURPA).

On October 5, 1979, the Commission issued rules to implement Title II and establish a mechanism for the incremental pricing program.[1] One provision of the October 5 rules implemented section 206(c)(3) of the NGPA for purposes of the incremental pricing program. This provision exempted from the incremental pricing program all gas used for cogeneration by qualifying cogeneration facilities under section 3(18)(B) of the Federal Power Act. However, at that time the Commission had not promulgated rules establishing the criteria for "qualifying cogeneration facilities" under section 3(18)(B) of the Federal Power Act. In order that the incremental pricing

[1] 18 CFR 282.202(e), 44 FR 37726 (October 5, 1979).

regulations might be workable, the Commission, on November 9, 1979, issued an interim rule for qualification of gas-fired cogeneration facilities for purposes of the incremental pricing program.[2] This interim rule established an exemption from incremental pricing for cogeneration facilities which were in existence and used natural gas as an energy input on or prior to November 1, 1979.[3]

On March 13, 1980, the Commission issued a final rule under section 201 of PURPA establishing requirements for a determination of qualifying status for small power production and cogeneration facilities.[4] This rule maintained criteria established in the interim rule, and also established additional criteria for other facilities not previously eligible under the interim rule[5] for eligibility for the exemption from incremental pricing set forth in 18 CFR 282.202(e).

The exemptions, however, were limited under section 3(18)(B) of the Federal Power Act to cogeneration facilities which produce *electric* energy, and another form of useful energy. Cogeneration facilities which produce *mechanical* energy and another form of useful energy are not elegible under the final rule for these exemptions from incremental pricing.

These types of facilities, however, can produce the same fuel efficiencies as can a cogeneration facility producing electric energy and another form of useful energy. Section 206(d) of the NGPA authorizes the Commission to exempt from incremental pricing any other industrial facility or category thereof; any exemption granted by the Commission under 206(d) is subject to Congressional review before it can become effective. The Commission believes that cogeneration facilities which produce mechanical energy should be afforded the same exemption from incremental pricing surcharges as is available to cogeneration facilities which generate electricity.

II. The Rationale for a 206(d) Exemption

Cogeneration involves the production of both useful heat had power through the sequential use of energy. Electricity and forms of energy such as shaft power, compressed air or hydraulic power, are all variations of the high-grade energy form known as mechanical power or energy. Production of any of these mechanical energy forms, with utilization of the reject heat from a facility, represents energy-efficient cogeneration with similar energy saving as is available form cogeneration involving the production of electricity.

The cogeneration incentive provided through the exemption from incremental pricing is intended to significantly promote energy conservation by cogeneration facilities. However, under the existing regulations, only those cogeneration facilities which generate electricity are eligible for the exemption; those producing only mechnical power are excluded. Not only is this distinction inequitable, since energy resources may be conserved absent electrical generation, but it may create a significant incentive for needless capital investment. For example, an industrial company with a need for mechanical power which could be obtained through cogeneration might have an economic incentive through lower natural gas prices to cogenerate electricity instead of mechanical power. This electricity would, in turn, used to power electric motors, which would be used to drive the machinery. Thus, several intermediate steps would have been taken to achieve the same result.

The expense of installing the generators and motors would be

[2] Docket No. RM79-54, issued November 9, 1979, 44 FR 65744 (November 15, 1979).

[3] 18 CFR 292.501-292.503, 44 FR 65744 (November 15, 1979).

[4] Order No. 70, issued March 13, 1980 in Docket No. RM79-54, "Final Rule Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities," 45 FR 17959 (March 20, 1980).

[5] 18 CFR 292.205(c).

needlessly incurred, since the cogeneration prime mover could directly supply the required mechanical power. Moreover, the intermediate conversion to electricity would result in energy losses since motors and generators are always less than perfectly efficient. By making mechanical cogeneration facilities eligible for the exemption from incremental pricing, the proposed rule would remove this inappropriate incentive to install unneeded equipment.

III. The Proposed Rule

The Commission wishes to emphasize that the proposed rule would not affect any of the provisions of Order Nos. 69 or 70 which pertain to electrical cogeneration.[6]

The proposed rule does, however, adopt certain terms and criteria used in Order No. 70 for qualifying electrical cogeneration facilities. In order to ensure that mechanical and electrical cogeneration facilities are afforded equivalent treatment under the incremental pricing provisions of the NGPA, this rule specifies that a mechanical cogenerator be exempted if it meets efficiency standards similar to those prescribed for electrical cogeneration facilities in Order No. 70. The proposed rule does not require theoretical conversion of mechanical energy to an electrical energy equivalent. A cogenerator developing only mechanical power most probably desires this form of energy for use in his facility. It is appropriate to relate this mechanical energy to an equivalent efficiency standard, rather than to attempt a determination of what quantity of electricity could reasonably be generated from the cogenerator's mechanical power.

The mechanical power produced by a cogeneration facility can assume several forms. Accordingly, the proposed rule provides that the useful mechanical energy output produced by a cogeneration facility be determined at the output of the prime mover. The power developed by the cogeneration heat engine, before conversion to other forms, may be considered to be the facility's mechanical power output. This means, for example, that the mechanical power output of a backpressure steam turbine driving an air compressor can be measured by the turbine shaft output. However, where there is no shaft, as in a free-piston compressor, the mechanical power output may be determined in terms of the work content of the pumped fluid. This rule should serve to simplify the calculation of a facility's output and efficiency. Since the proposed rule does not require measurement following any subsequent mechanical energy conversions, no incentives are provided to utilize any particular form of mechanical energy.

However, the rule is discretionary in this respect and therefore does not require measurement at the output of the prime mover, since measurement at subsequent energy conversion points may be easier and cannot result in a higher measurement of energy efficiency than measurement at the prime mover.

Mechanical power may be measured at conversion points subsequent to the prime mover. The Commission requests specific comments as to whether the term "output of the prime mover" is appropriate and whether the application of this provision should be permissive in this respect. Comments are also requested on the feasibility of measuring mechanical power output.

In Order No. 70, the Commission noted that if and when final regulations under Phase II of incremental pricing take effect, and the Commission can better assess their implications, the Commission may wish to revise the exemptions from incremental pricing granted to cogeneration facilities qualifying under that rule.[7] The Commission intends that the exemption for mechanical cogeneration facilities will be given similar review and treatment.

[6] Order No. 69, 45 FR 12214 (February 25, 1980), and Order No. 70, 45 FR 17959 (March 20, 1980).

[7] Order No. 70, *supra* note 4, mimeo at 62.

IV. Congressional Review

The regulations below are being proposed pursuant to section 206(d) of the NGPA. Thus, if the regulations are adopted by the Commission as a final rule, they will be submitted to the Congress for review prior to taking effect. After the regulations are submitted to each House of Congress, they may take effect following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30 day period.

V. Comment Procedures

A. Written Comments

The Commission invites interested persons to submit written comments on the matter proposed in this notice. An original and 14 conformed copies of such comments should be filed with the Commission by June 30, 1980. Each of the issues presented in the written comments should appear in a separate paragraph. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, DC 20426. All comments should refer to Docket No. RM80–62.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE, Washington, DC 20426. The Commission will consider all timely comments before acting on the matters proposed in this notice.

B. Public Hearing

A public hearing concerning this proposal will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, DC 20426 on July 1, 1980 beginning at 10:00 a.m. EST, and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:00 p.m., on June 20, 1980.

Requests to participate in the hearing should include a reference to Docket No. RM80–62, as well as a concise summary of the proposed oral presentation and a telephone number where the person making the presentation may be reached. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:30 p.m. on June 25, 1980. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 10 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Division of Public Information, Office of Congressional and Public Affairs.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 3 CFR Part 142 (1978), Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282, Subchapter H, Chapter 1 of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.204 is amended in paragraph (d)(3)(i) by changing the designation of clauses (F), (G), (H), and (I) to (G), (H), (I) and (J) respectively and adding new clauses (F) and (K) to read as follows:

§ 282.204 Obtaining an exemption.

* * * * *

(d) *Exemption on the basis of an affidavit.* * * *

(3) *Contents of exemption affidavit.* (i) * * *

(F) Is the customer's facility, in its entirety, a mechanical cogeneration facility?

* * * * *

(K) Is the customer's facility, in part but not in its entirety, a mechanical cogeneration facility?

* * * * *

2. The Table of Sections for Part 282 is amended to add a new § 282.211 entitled "*Exemptions for mechanical cogeneration facilities under NGPA section 206(d).*"

3. Part 282 is amended by adding a new § 282.211 to read as follows:

§ 282.211 Exemptions for mechanical cogeneration facilities under NGPA section 206(d).

(a) *Definitions and general rules.* For purposes of this section:

(1) "Mechanical cogeneration facility" means equipment used to produce mechanical energy and forms of useful thermal energy (such as heat or steam), used for industrial or commercial heating or cooling purposes, through the sequential use of energy;

(2) "Topping-cycle mechanical cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful mechanical power output, and the reject heat from such power production is then used to provide useful thermal energy;

(3) "Bottoming-cycle mechanical cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then use to produce useful mechanical power output;

(4) "Supplementary firing" means an energy input to the mechanical cogeneration facility used only in the thermal process of a topping-cycle mechanical cogeneration facility, or only in the mechanical power production process of a bottoming-cycle mechanical cogeneration facility;

(5) "Useful mechanical power output" of a mechanical cogeneration facility means the total mechanical energy made available for use, exclusive of any such energy used in the mechnical energy production process;

(6) "Useful thermal energy output" of a topping-cycle mechanical cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or use in any heating or cooling application;

(7) "Total energy output" of a topping-cycle mechnical cogeneration facility is the sum of the useful mechanical power output and useful thermal energy output;

(8) "Total energy input" means the total energy of all forms supplied from external sources;

(9) "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas;

(10) "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products;

(11) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of the natural gas or oil; and

(12) Useful mechanical power output may be measured at the output of the prime mover or at a subsequent energy conversion point.

(b) *Exemption from incremental pricing. Topping-cycle facilities.* Natural gas used in any topping-cycle mechanical cogeneration facility is eligible for an exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules if the facility meets the operating and efficiency standards under paragraphs (c)(1) and (c)(2) of this section.

(c) *Operating and efficiency standards for topping-cycle mechanical cogeneration facilities.* (1) *Operating standard.* For any topping-cycle mechanical cogeneration facility, the useful thermal energy output of the facility must, during any calendar year period, be no less than 5 percent of the total energy output.

(2) *Efficiency standard.* For any topping-cycle mechanical cogeneration facility for which any of the energy input is natural gas or oil, the useful mechanical energy output of the facility plus one-half the useful thermal energy output, during any calendar year period, must:

(i) subject to clause (ii), be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

(ii) if the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.

(d)(1) *Efficiency standards for bottoming-cycle facilities.* For any bottoming-cycle mechanical cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, the useful mechanical power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

(2) *Bottoming-cycle facilities.* Natural gas used in any bottoming-cycle mechanical cogeneration facility other than gas used for supplementary firing, is eligible for an exemption under Title II of the NGPA and Part 282 of the Commission's rules:

(i) if the facility meets the efficiency standard under paragraph (d) of this section, and

(ii) to the extent that reject heat emerging from the useful thermal energy process is made available for use for mechanical power production.

(3) *Supplementary firing.* Natural gas used for supplementary firing in any mechanical cogeneration facility is not eligible under this section for exemption from incremental pricing.

(e) *Waiver.* The Commission may waive any of the requirements of paragraphs (b), (c) and (d) upon a showing that the facility will produce significant energy savings.

¶ 32,069 Determination of Alternative Fuels for Essential Agricultural Users

45 F. R. 39283 (June 10, 1980).

18 CFR Part 281

[Docket No. RM79-40]

Determination of Alternative Fuels for Essential Agricultural Users

June 3, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it is proposing to adopt a final rule, pursuant to section 401(b) of the Natural Gas Policy Act of 1978, to provide for the determination of alternative fuels that are reasonably available and economically practicable for essential agricultural users. The proposed rule would provide that coal and residual fuel oil are reasonably available and economically practicable alternative fuels for essential agricultural users that have the ability to use those fuels. The proposed rule would apply only to those essential agricultural users that have requested from a direct supplier priority 2 entitlements exceeding 300 Mcf on a peak day. New boilers with a capacity exceeding 300 Mcf per day would be deemed to have alternative fuel capability.

DATE: Written comments by July 3, 1980. Request to participate in hearing by June 20, 1980. Hearing date: June 30, 1980.

ADDRESS: Written comments and request to participate to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE, Washington, D.C. 20425 (Reference Docket No. RM79-40).

HEARING LOCATION: Federal Energy Regulatory Commission, 825 North Capitol Street NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Robert F. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE, Washington, D.C. 20426, (202) 357-8432.

I. Background

In Order No. 55, issued on October 26, 1979, the Commission issued an interim rule implementing section 401(b) of the Natural Gas Policy Act (NGPA).[1] The interim rule established that alternative fuel determinations would be made generically rather than case by case. In that rule the Commission determined that, for the 1979–1980 heating season, coal and residual fuel oil were reasonably available and economically practicable for essential agricultural users. The rule applied only to agricultural establishments with requirements exceeding 300 Mcf per day. In addition, new boilers with a capacity in excess of 300 Mcf per day were deemed to have alternative fuel capability.

At the time Order No. 55 was issued, the Commission indicated that the issues of reasonable availability and economic practicability would be considered anew at the end of the 1979–1980 heating season.

In exercising its statutory mandate to consider the "reasonable availability" and "economic practicability" of alternative fuels the Commission has

ERR14 [1] Section 401(a) of the NGPA provides that essential agricultural uses of natural gas may not be curtailed except to the extent necessary to meet high priority uses. Section 401(b), however, provides that the curtailment status of section 401(a) shall not apply to those essential agricultural uses for which the Commission, in consultation with the Secretary of Agriculture, determines that an alternative fuel is reasonably available and economically practicable.

reviewed data from various sources. The data do not in all cases, lead to a single definitive conclusion. Moreover, Congress has not imposed a statutory test which may be applied by use of a simple formula. Thus, the Commission has exercised its discretion in reaching its conclusion that coal and residual fuel oil are reasonably available and economically practicable. It seeks comment on this proposed rule.

The Commission has transmitted a copy of this proposed rule to the Department of Agriculture and requested its comments.[2] The Commission will continue to consult with the Department of Agriculture while the proposed rule is under consideration, as provided in section 401(b) of the NGPA.

II. Discussion

Under the final rule proposed herein coal and residual fuel oil would be considered both reasonably available and economically practicable on a nationwide basis. The proposed rule would retain the mechanical features of the interim rule. The alternative fuel determination would continue to be made on a generic basis and the procedural features would remain essentially the same. Although the proposed rule would be a final rule, it may be amended from time to time as circumstances require.[3] The adjustment procedures of section 502(c) of the NGPA will enable us to avoid undue hardship that a generic rule might otherwise cause to individuals.

A. Other Issues Determined in Order No. 55

Besides determining what fuels were economically available and reasonably practicable in Order No. 55, the Commission also decided that agricultural users with a capacity less than 300 Mcf per day would be exempt from the rule. In addition, all new boilers with a capacity exceeding 300 Mcf per day would be deemed to have alternative fuel.

The proposed rule would continue the exemption of the interim rule excluding essential agricultural users who requested, from a direct supplier, less than 300 Mcf per day in priority 2 entitlements. This criterion is clarified under the proposed rule to apply specifically to requests of 300 Mcf on a peak day. This is consistent with Commission treatment of small users in many curtailment plans. We also think that it may be administratively burdensome to gather data on all users under 300 Mcf per day.

Modern boilers are frequently constructed with the capability to use residual fuel oil as an alternative to natural gas. Consequently, the proposed rule would continue the position taken in Order No. 55: All new boilers with a capacity greater than 300 Mcf per day except for turbines and diesels designed to use distillate fuel oil as the only alternative to gas, are deemed to have alternative fuel capability.

Comments are invited on the proposal to retain these features of the interim rule.

B. Availability of Alternative Fuels

Over the long term the nation faces an energy shortage that affects all fuels. Nevertheless, we do not think that Congress was referring to this long term view when it authorized the Commission to determine what fuels

[2] In response, USDA (1) indicates that it is concerned about price disparity between gas and residual fuel oil in different regions, (2) asks what would constitute a significant change in circumstances that would cause the rule to be amended, and (3) suggests residual fuel oil and coal should be presumed to be alternatives to gas to the extent that their delivered cost to a particular agricultural user does not exceed a given percent of the delivered cost of natural gas. A copy of USDA's comments is available in the public file of this proceeding, Docket No. RM79-40, in the Commission's Office of Public Information.

[3] The Commission recognizes the need for agricultural users to make arrangements for alternative fuels. Therefore, the Commission intends to the maximum extent practicable, to make any necessary changes in the alternative fuel rule before the commencement of the winter heating season to allow those affected by the rule to arrange for alternative fuels.

were reasonably available and economically practicable for purposes of section 401(b).

In Order No. 55, the interim rule, the Commission determined that coal and residual fuel oil were reasonably available for the then approaching heating season. The Commission also found that the record did not provide a sufficient basis for finding distillate fuel oil and propane to be reasonably available fuels within the meaning of section 401(b). Under the rule proposed herein, coal and residual fuel oil would continue to be considered reasonably available.

When the interim rule was under consideration, no commentators seriously opposed the proposal to find that coal was a reasonably available fuel. Recent data published by the Energy Information Administration (EIA) of DOE indicate that availability of coal has increased since Order No. 55 was issued. During 1979, consumption and exports of coal increased. Imports decreased. Nevertheless, total stocks of coal held by consumers at the end of 1979 were 179.6 million tons, 23.4 percent greater than they were at the end of 1978.[4] This data strongly suggest that coal must continue to be considered a reasonably available fuel.

Primary stock totals for residual fuel oil during the week of May 2, 1980, were 83.5 million barrels, 3.0 percent higher than the 81 million barrels held in April 1979.[5] For the previous twelve months primary stocks have exceeded their level for the corresponding month of the previous year. In addition, since last fall, primary stocks of residual fuel oil have remained well above the minimum acceptable level estimated by EIA, as indicated in Figure 1 below.

[4] See DOE/EIA Monthly Energy Review, March 1980, at 53. Import data refer only to bituminous coal, since no anthracite coal is imported.

[5] EIA Weekly Petroleum Status Report, May 9, 1980, at 7. EIA defines residual fuel oil as including No. 5 and 6 fuel oil that conforms to ASTM Specification D396, heavy diesel oil, Navy Special Oil, Bunker C oil, and acid sludge and pitch used as refinery fuels.

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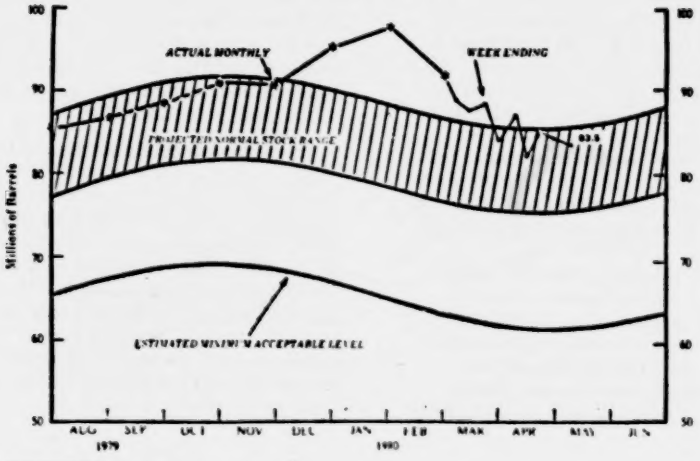
FIGURE 1 6/
Residual Fuel Oil Stocks at Primary Level
as of May 2, 1980



[6] Source: EIA Weekly Petroleum Status Report, May 9, 1980, at 16. "Estimated minimum acceptable level" represents the industry level at which spot shortages are probable.

On a regional basis, the supply picture is similar. During April, primary stocks were higher in every PADD Region, except the Gulf Coast, than they were in April 1979.[7]

In Order No. 55 [8] the Commission expressed "guarded optimism" about the availability of heating oil during the 1979–80 heating season. Nevertheless, it was felt that because of the complex, uncertain variables involved, and the danger of creating unanticipated demands in the market for home heating oil, there was not an adequate basis for finding distillate fuel oil to be reasonably available. Since November 1979, however, primary stocks for distillate fuel oil [9] have been consistently above the EIA projected normal stock range and significantly above the "estimated minimum acceptable level." (See Figure 2 below). During the week of May 2, 1980, previous stocks of distillate fuel oil were 177.6 million barrels, 54.4 percent more than the 115.0 held in April 1979.[9]

[7] *Id.* at 18. PADD Regions are Petroleum Administration for Defense Districts.

Primary stocks for residual fuel oil decreased somewhat in the Gulf Coast Region during April and the first week of May. Given what appears to be a nationwide availability of residual fuel oil, however, it does not necessarily follow that residual fuel oil is not reasonably available in that region.

[8] Order No. 55 was issued October 26, 1979.

[9] EIA's definition of distillate fuel oil includes No. 1 and No. 2 heating oils, diesel fuels, and No. 4 fuel oil, which conform to either ASTM Specification D396 or D975.

[9] *Id.* at 7.

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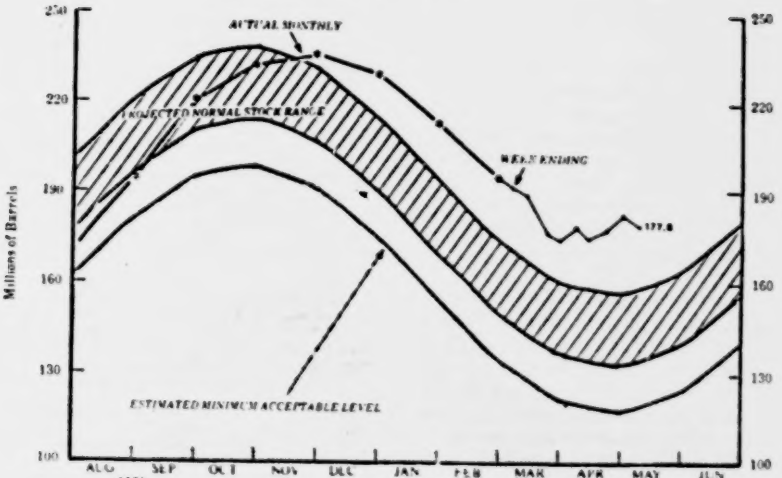
Figure 2 10/

Distillate Fuel Oil Stocks at Primary Level
as of May 2, 1980



10/ Id. at 13.

During April, stocks were significantly higher than in April 1979 for every PADD region.[11] Despite this increase in previous stocks the amount of distillate fuel oil supplied [12] for the four week period ending May 12, 1980, averaged 16 percent less than at the same time last year.[13] This suggests a reduction in demand, which is consistent with a finding of increased availability. It therefore appears that distillate fuel oil should be considered reasonably available.

The Commission also notes that on April 18, 1980, stocks of crude oil and major petroleum products were significantly higher than at this point in previous years. Since the markets for all fuel oil products are related, this would tend to suggest that some stability in the availability of fuel oils may be expected, at least for the near term.

Over the last year, nationwide inventories of propane have declined approximately 6.7 percent, according to data published by the American Petroleum Institute.[14] Over 70 percent of these inventories are located in the Mid Continent and Gulf Coast areas.[15] The Commission invites comment on

[11] *See id.* at 15.

[12] EIA defines "products supplied" as a calculated value computed for specific products as domestic production plus net imports (imports less exports), less the net increase in primary stocks.

[13] *Id.* at 26.

[14] API Liquified Petroleum Gas Report, March 31, 1980. The Mid Continent area includes the states of North Dakota, South Dakota, Minnesota, Wisconsin Nebraska, Iowa, Kansas, Missouri, and Oklahoma. The Gulf Coast area includes Texas Railroad Commission Districts 2, 3, and 4 and the following parishes of the state of Louisiana: Vernon, Rapides, Avoyelles, Pointe Coupee, W. Feliciana, E. Feliciana, Tangipahoa, Washington, and all parishes south thereof.

[15] *See Id.*

whether or not propane should be considered reasonably available and economically practicable. Those commenting are strongly urged to support their views with data to the extent they are available.

c. Economic Practicability of Alternative Fuels

Recent data indicate that, of the alternative fuels that are reasonably available, coal and residual fuel oil are also economically practicable. Available data do not in the Commission's judgment, provide an appropriate empirical basis for it to exercise its statutory discretion and find that distillates are also economically practicable.

The Commission intends to exercise its statutory discretion to consider the concept of "economically practicable" by assessing alternate fuel prices relative to the price of natural gas. In so doing, we propose to limit application of the term to those essential agricultural users who presently have installed ability to use those fuels which are periodically determined to be economically practicable.

We have compared the weighted average prices paid for coal, distillate, and residual fuel oil, during 1979 with the price of natural gas. The weighted average fuel prices used in our evaluation were taken from data reported by electric utilities on FPC Form 423. A comparison of 1979 fuel prices, on a nationwide basis, is shown on the table below.

Comparative 1979 Fuel Prices [1]

(Differential between alternate fuel price and gas price)

Type of fuel	Fuel price (¢/MMBtu)	Gas price (¢/MMBtu)
Fuel oil:		
No. 2	402.0	226.6
Low Sulfur No. 6 [2] [3]	320.2	144.8
High Sulfur No. 6 [2] [4]	264.7	89.3
All No. 6 [3]	299.7	124.3
Coal: All grades	122.4	(53.0)
Natural gas	175.4	

[1] Source: FPC Form No. 423, annual summary data for 1979.

NOTE: All prices are delivered prices for steam electric plants.

[2] Includes minor amounts of No. 4 and No. 5 fuel oil, crude and topped crude.

[3] Low sulfur oil has one percent or less sulfur content.

[4] High sulfur oil has greater than one percent sulfur content.

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The following table shows a regional comparison of alternative fuel and natural gas prices during 1979.

REGIONAL COMPARISON OF FUEL PRICES

REGIONAL COMPARISON OF SELECTED FUEL PRICE DATA - 1979

Census Region	Coal Price (All Grades) (¢/MMBtu)	Fuel Oil Prices No. 2 (¢/MMBtu)	Fuel Oil Prices No. 6 1/ (¢/MMBtu)	Natural Gas Prices Form 423 (¢/MMBtu)	Natural Gas Prices Rank (No.)	Alternate Fuel Price Differentials Compared to Form 423 Natural Gas Prices: Coal (¢/MMBtu)	Coal (%)	No. 2 (¢/MMBtu)	No. 2 (%)	No. 6 (¢/MMBtu)	No. 6 (%)
1. New England	152.9	429.4	292.3	267.6	1	(114.7)	(42.9)	161.8	60.5	24.7	9.2
2. Mid. Atlantic	124.5	391.6	309.1	236.0	4	(111.5)	(47.2)	155.6	65.9	73.1	30.9
3. E.N. Central	133.5	386.8	344.0	246.9	2	(113.4)	(45.9)	139.9	56.7	97.1	39.3
4. W.N. Central	100.7	385.0	225.8	149.5	8	(48.8)	(32.6)	235.5	157.5	76.3	51.0
5. So. Atlantic	141.2	455.3	293.2	136.2	9	5.0	3.7	319.1	234.3	157.0	115.3
6. E.S. Central	132.9	428.1	218.0	187.3	6	(54.4)	(29.0)	240.8	128.6	30.7	16.4
7. W.S. Central	100.7	349.1	259.8	156.8	7	(56.1)	(35.8)	192.3	122.6	103.0	65.7
8. Mountain	69.1	469.7	284.6	209.0	5	(139.9)	(66.9)	260.7	124.7	75.6	36.2
9. Pacific	83.6	321.3	313.8	244.7	3	(161.1)	(65.8)	78.6	32.1	69.1	28.2
Total U.S.	122.4	402.0	299.7	175.4		(53.0)	(30.2)	226.6	129.2	124.3	70.9

Source: FPC Form No. 423, as reported in DOE/EIA Energy Data Report, Cost and Quality of Fuels for Electric Utility Plants - 1979.

1/ Includes prices paid for minor amounts of No. 4 and No. 5 fuel oil, crude and topped crude.

Within each region, the price differences are similar to the national data in that No. 2 fuel oil prices are higher than the prices paid for No. 6 fuel oil; No. 6 is priced higher than natural gas; and coal is generally less expensive than natural gas. Actual fuel prices, of course, vary from region to region as well as from state to state. However, the national fuel price relationships remain essentially the same on a regional basis. Moreover, it does not appear that the benefits of a regional rule would outweigh the administrative burdens associated with such a rule. Therefore, our determination of economic practicability in this proposed rulemaking will be based on national rather than regional determinations. However, the Commission continues to weigh the possibility of regional determinations and seeks comment on the issue. Those supporting a regional rule should submit available data as well as commentary.

Our examination of a number of other sources of fuel price information leads us to believe that the Form 423 data is the most reliable, detailed and current source of price information available and therefore the best statistical basis for the Commission analyses. In our search for representative fuel prices paid by agricultural users we have specifically noted the prices published in DOE's Monthly Energy Review (MER) as well as other DOE publications.

A comparison of DOE's Monthly Energy Review and FERC Form 423 price data for fuel oil, coal, and natural gas over the last four years is shown in the attached Appendix A. Although the absolute price levels between the two price series may vary, the price differentials have generally been consistent. Appendix B illustrates graphically the movement of fuel oil prices, as reported by electric utilities since 1976. Appendix B also shows the price relationship of natural gas to No. 2 fuel oil and residual fuel oil prices over the same four year period.

We invite comments on the availability and advantages of other existing fuel price data that might be used by the Commission in analyzing economic practicability.[16]

After consideration of the available price data, as well as current price trends it is our judgment that we lack the appropriate empirical basis to make a finding that distillate fuel oil is economically practicable within the meaning of section 401(b) of the NGPA. It is our further judgment that the relevant empirical data lead to the conclusion that coal and No. 6 residual fuel oil (both high and low sulfur) are economically practicable. The Commission invites comments on this judgment. Those who would have the Commission exercise its statutory discretion in a different manner should spell out in detail the statutory and

[16] Fuel oil price data are currently being collected under Title II of the NGPA—the incremental pricing provisions. In our Order No. 50 (issued September 28, 1979) we provided for the collection of certain data by the Energy Information Administration to determine alternate fuel prices charged to non-utility industrial users. EIA was originally requested to collect monthly data by states from all fuel oil sellers regarding the prices they charge for No. 2 fuel oil, No. 6 high sulfur fuel oil, and No. 6 low sulfur fuel oil. The price data would exclude state or local taxes and cover sales in lots of over 4,000 gallons. This was the so-called "three-tier" approach.

In Order No. 51 (issued September 28, 1979) we exempted industrial boiler fuel facilities from incremental pricing above the ceiling price of No. 6 high sulfur fuel as provided for in Order No. 50. Order No. 51 postponed implementation of the upper two price ceilings (No. 2 fuel oil and low sulfur No. 6 fuel oil) until November 1, 1980. (Order No. 81 issued May 7, 1980, further postponed implementation of the first two tiers for an additional year, until November 1, 1981, because of uncertainties about the ability to implement an accurate three-tier ceiling.) Currently, EIA only collects high sulfur No. 6 fuel oil price data.

No. 6 high sulfur fuel oil prices are published monthly by EIA as alternative fuel price ceilings. These are "adjusted" prices and do not reflect actual weighted average prices. Rather, they represent the lower end of a range of average prices paid for No. 6 high sulfur fuel oil. While the monthly alternative fuel price ceilings published by EIA are appropriate for incremental pricing under Title II of the NGPA, we believe that they do not provide as good a basis for Commission judgments as other data series provide.

empirical basis for making the suggested alternative determination.

D. Environmental Assessment

The Staff has completed an environmental assessment of the proposed rule. The assessment is based on a worst-case assumption that the Commission might determine that all residual and distillate fuel oils as well as coal and propane are reasonably available and economically practicable.

As discussed, the Commission does not propose such a rule, but the assessment provides a useful basis for analyzing the rule that the Commission does propose. One must keep in mind, however, that by its very nature, the staff assessment overstates the adverse economic impacts on agriculture.

In preparing the assessment, the Staff relied primarily on data contained in the Energy Information Administration (EIA) Form 50 reports for 1979. The assessment is based on the assumption that curtailments will be no worse than in the 1978–79 heating season, as reflected in the EIA Form 50 data. Curtailments in the near future are actually expected to be less than occurred during the 1978–79 heating season.

In its environmental assessment, the staff analyzed the national and regional effects of determining various alternative fuels to be reasonably available and economincally practicable for purposes of section 401(b). It was determined that even under the worst case hypothesis described above, the effects of the proposed rule on air quality would be insignificant. Any adverse impact on air quality attributable to increased reliance on alternative fuels by agricultural users would probably be offset by corresponding decreases in emissions by other industrial users whose curtailment would decrease. The assessment also concludes that the effect of the worst case hypothesis on agricultural costs of production would be small—less than one percent of the value added in manufacturing by essential agricultural users.

The environmental assessment has been placed in the public files of the Commission and is available for public inspection in the FERC's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426. Copies are available in limited quantities from the Office of Public Information. Comments are invited.

For further information on the environmental assessment, contact Richard R. Hoffman, Project manager (202) 357–8098.

III. Section-by-Section Analysis

Section 281.203 Definitions and cross-references

Section 281.203(a)(17), which defines "currently effective curtailment plan" would be revoked. The phrase is self-defining.

Section 281.204 Tariff filing requirements

Section 281.204(b)(3) provides that the index of entitlements shall not include the volumes of natural gas for which the essential agricultural user has the ability to use an alternative fuel as determined under Subpart C. Each interstate pipeline is required to amend its index of entitlements to remove from the priority 2 classification and place in an appropriate priority of service category "any volumes of natural gas included in any index of entitlements that is effective on October 31, 1979 (or on November 30, 1979, if the pipeline elects to file tariff sheets under paragraph (a)(2) of this section)." Under the proposed rule, a pipeline would be required to amend its index of entitlements "pursuant to paragraph (b)(2)" to remove from the priority 2 classification and place in an appropriate priority of service category "any such volumes of natural gas included in any index of entitlements that is effective on or after October 31, 1979 (or on November 30, 1979, if the pipeline elects to file tariff sheets under (a)(2) of this section)."

A new § 281.204(b)(4) would be added to provide that notwithstanding any

thing in paragraph (b)(2) (periodic update of the index of entitlements), a pipeline may elect to file its revised index of entitlements on November 1, 1980, with a proposed effective date of December 1, 1980, if the pipeline (i) files, with the Secretary, by October 1, 1980, a written notice of its decision to file its revised index on November 1, 1980, and (ii) continues its existing index in effect until December 1, 1980.

Section 281.211 Filing and documentation

Section 281.211(b)(1)(ii)(D) would be amended to provide that a request for classification of essential agricultural requirements as priority two entitlements shall include, with respect to any agricultural user to which Subpart C (alternative fuel determinations) applies, the data and calculations necessary to determine alternative fuel volumes under § 281.304.

Section 281.211(b)(4)(ii) would be amended to provide that for years subsequent to 1979, the data required by this paragraph must be filed only to the extent that there has been a change in essential agricultural requirements. This amendment would make it clear that changes resulting in reduced agricultural requirements must be filed, as well as requests for changes reflecting increased requirements.

Section 281.216 Filing and service dates for 1980

Section 281.216 would be amended by designating the existing paragraph [17] as paragraph (a) and by adding a new paragraph (b) to provide that if the pipeline elects to file its revised index of entitlements on November 1, 1980, under § 281.204(b), the data verification committee shall submit its report on October 23, 1980.

Section 281.302 Applicability

Section 281.302(a)(2) applies Subpart C to essential agricultural users that have requested priority 2 requirements in excess of 300 Mcf per day. The proposed rule would clarify this requirement by amending the phrase to reas: "300 Mcf on a peak day."

Section 281.303 Definitions

Section 281.303(a) defines "ability to use" an alternative fuel as meaning that an essential agricultural use establishment had, on August 29, 1979, the installed physical capability to use the alternative fuel and has used that alternative fuel, in any amount, at any time after 1973, for an essential agricultural use.

The proposed rule would amend this section by inserting the phrase "or thereafter acquired" after "on August 29, 1979."

Section 261.303(h) defines "essential agricultural requirements" to mean volumes of natural gas certified by the Secretary of Agriculture and calculated in accordane with 7 CFR 2900.4. The proposed rule would clarify this section by adding the words "and § 281.208(b) of this Chapter" to the end of the sentence.

Section 281.305 Filing of amendments to essential agricultural requirements and priority 2 entitlements

Under the interim rule of Order No. 55, this section provided for filing amendments to priority 2 entitlements to reflect alternative fuel volumes. Since that process has been completed, § 281.305(a), (b)(2), (c), and (d) are no longer necessary and would be deleted. The section would be recaptioned "General rule." The (b) designation would be deleted from former § 281.305(b), and that section would be amended to provide that any essential agricultural user subject to this subpart that has requested from any direct supplier priority 2 classification for volumes for any essential agricultural use establishment shall reduce its essential agricultural requirements

[17] Contemporaneously with this notice, the Commission is issuing a rule in Docket No. RM79-15 adding a new § 281.216(a). The rule, which is effective immediately, provides that, under Subpart B, filing and service dates for 1980 shall be the same as for 1979, notwithholding anything to the contrary in § 281.212(d) or § 281.213(c).

calculated under § 281.208 to reflect the exclusion of volumes of natural gas for which its essential agricultural establishment has alternative fuel volumes under § 281.304.

The reference to § 281.207 in former § 281.305(b)(1) was a typographical error. Proposed § 281.305 would correct this to refer to § 281.208.

IV. Comment Procedures

A. *Written Comments*

Interested persons are invited to submit written comments on this proposed rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM79–40. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, July 3, 1980, will be considered by the Commission prior to promulgation of a final rule. All written submissions will be available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours. The Commission will consider all timely comments before acting on matters proposed in this notice.

B. *Public Hearings*

A public hearing concerning this proposal and the interim rule issued on June 3, 1980, in Docket No. RM79–15 [18] will he held in Washington, D.C. on June 30, 1980, beginning at 10:00 a.m. at the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing.

Requests to participate should be directed to the Secretary at the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, no later than June 20, 1980. Requests should reference Docket No. RM79–40, should indicate the amount of time desired for the oral presentation and the telephone number where the person making the request may be reached. Persons participating in the public hearings should, if possible, bring 50 copies of their testimony to the hearing. A list of participants in the hearing will be available in the hearing room on the morning it is convened.

Members of the hearing panel will be designated by the Chairman of the Commission. The hearing will not be judicial or evidentiary-type hearing. there will be no cross-examination of persons presenting statements.

However, the panel may question such persons, and any interested person may submit questions to the presiding officer who will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearings. Transcripts of the hearings will be available in the public file for this proceeding, Docket No. RM79–40, in the Commission's Office of Public Information.

(Natural Gas Act amended (15 U.S.C. 717–717w); Natural Gas Policy Act of 1978 (15 U.S.C. 3301–3432); Department of Energy Organization Act (42 U.S.C. 7101–7352); E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, it is proposed to amend Part 281, Chapter I of Title 18, Code of Federal Regulations, to read as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

§ 281.203 [Amended]

1. Section 281.203(a)(17) is revoked.

2. Section 281.204 is amended in paragraph (b) by revising the second sentence of paragraph (b)(3) and by adding a new paragraph (b)(4), to read:

[18] See n. 19 supra.

§ 281.204 Tariff filing requirements.

* * * * *

(b) * * *

(3) * * * Each interstate pipeline shall amend its index of entitlements pursuant to paragraph (b)(2) of this section to remove from the priority 2 classification and place in an appropriate priority of service category any such volumes of natural gas included in any index of entitlements that is effective on or after October 31, 1979 (or on November 30, 1979, if the pipeline elects to file tariff sheets under paragraph (a)(2) of this section).

(4) Notwithstanding paragraph (b)(2) of this section, a pipeline may elect to file its revised index of entitlements on November 1, 1980 with a proposed effective date of December 1, 1980, if the pipeline:

(i) Files with the Secretary no later than October 1, 1980, a written notice of its decision to file its revised index of entitlements on November 1, 1980; and

(ii) Continues its existing index of entitlements filed under this subpart B until December 1, 1980.

* * * * *

3. Section 281.211 is amended by revising paragraph (b)(1)(ii)(D) and by revising the first sentence of paragraph (b)(4)(ii), to read as follows:

§ 281.211 Filing and documentation.

* * * * *

(b) *Priority 2.* * * *

(1) *Essential agricultural users.* * * *

(ii) * * *

(D) Includes with respect to any essential agricultural user to which Subpart C applies the data and calculations necessary to determine alternate fuel volumes under § 281.304.

* * * * *

(4) *Subsequent request.* * * *

(ii) For years subsequent to 1979, the data required by this paragraph must be filed only to the extent that there has been a change in essential agricultural requirements.

* * * * *

4. Section 281.216 is amended by designating the existing paragraph as paragraph (8) and by adding paragraph (b) to read as follows:

§ 281.216 Filing and service dates for 1980.

(a) * * *

(b) The Data Verification Committee shall submit its report on October 23, 1980, if the pipeline has elected under § 281.204(b) to file its revised index of entitlements on November 1, 1980.

§ 281.302 [Amended]

5. Section 281.302(a)(2) is amended by deleting the word "per" between the words "Mcf" and "day", and by inserting in lieu thereof the words "on a peak."

§ 281.303 [Amended]

6. Section 281.303 is amended by adding in paragraph (a) the words "or thereafter acquired" between "1979," and "the", and by adding at the end of paragraph (h) the words "and § 281.208(b) of this chapter."

§ 281.304 [Amended]

7. Section 281.304(a)(2) is amended by adding the term "or thereafter acquired," between "1979" and the word "the".

8. Section 281.305 is revised to read as follows:

§ 281.305 General rule.

Any essential agricultural user subject to this subpart that has requested from any direct supplier priority 2 classification for volumes for any essential agricultural use establishment shall reduce its essential agricultural requirements calculated under § 281.208 to reflect the exclusion of volumes of natural gas for which its essential agricultural establishment has alternative fuel volumes under § 281.304.

APPENDIX A

COMPARISON OF SELECTED FUEL PRICE DATA
FPC FORM NO. 423 V. MONTHLY ENERGY REVIEW
1976 - JANUARY 1980

Type of Fuel	FPC Form No. 423 Price Data 1/					Monthly Energy Review Price Data 2/				
	1976	1977	1978	1979	Jan '80	1976	1977	1978	1979	Jan '80
	¢/MMBtu									
Fuel Oil										
No. 2	239.1	264.3	271.9	402.1	564.4	226.4	257.3	268.2	403.1	537.2
Low Sulfur No. 6	207.1	229.1	225.1	328.2	453.3	193.6	221.3	216.8	322.4	466.5
High Sulfur No. 6	168.7	199.9	186.7	264.7	361.4	165.9	195.2	186.1	261.5	349.6
All No. 6	195.9	220.4	212.5	299.9	423.5	182.8	210.4	202.7	297.0	417.7
Coal										
All Grades	81.4	84.8	94.7	111.6	128.7	3/	3/	3/	3/	3/
Natural Gas	103.4	130.0	143.8	175.4	194.8	97.2	131.9	154.1	201.8	237.3
	Actual Price Difference (Fuel Oil and Coal v. Natural Gas)									
Fuel Oil										
No. 2	131.7	134.3	128.1	226.7	369.6	129.2	125.4	114.1	201.3	299.9
Low Sulfur No. 6	103.7	99.1	81.3	144.8	258.5	96.6	89.4	62.7	120.6	229.2
High Sulfur No. 6	65.3	69.1	42.9	89.3	166.6	68.7	64.3	32.0	59.7	112.3
All No. 6	92.5	90.4	68.5	124.3	228.7	85.6	78.5	48.6	95.2	180.4
Coal										
All Grades	(22.0)	(45.2)	(49.1)	(63.8)	(66.1)	3/	3/	3/	3/	3/
	Price Difference Ratio 4/ (Fuel Oil and Coal v. Natural Gas)									
	Ratio									
Fuel Oil										
No. 2	1.274	1.013	.891	1.292	1.847	1.329	.931	.740	.998	1.264
Low Sulfur No. 6	1.003	.762	.565	.826	1.327	.992	.678	.407	.599	.966
High Sulfur No. 6	.632	.538	.298	.509	.855	.707	.480	.208	.296	.473
All No. 6	.895	.695	.476	.709	1.174	.881	.595	.315	.472	.760
Coal										
All Grades	(.213)	(.348)	(.341)	(.364)	(.339)	3/	3/	3/	3/	3/

1/ As reported in DOE/EIA Energy Data Report entitled Cost and Quality of Fuels for Electric Utility Plants (Annual summary data 1976-1979) and Monthly Report for January 1980. Note: All prices are delivered prices to steam electric plants. Prices paid for No. 6 fuel oil include prices paid for minor amounts of No. 4 and No. 5 fuel oil, crude and topped crude.

2/ Fuel oil prices are reported on FEA Form P302-M-1, "Petroleum Industry Monthly Report for Product Prices." Natural Gas Prices are those paid by industrial customers of major interstate pipeline companies as reported on FPC Form No. 11, "Natural Gas Pipeline Company Monthly Statement."

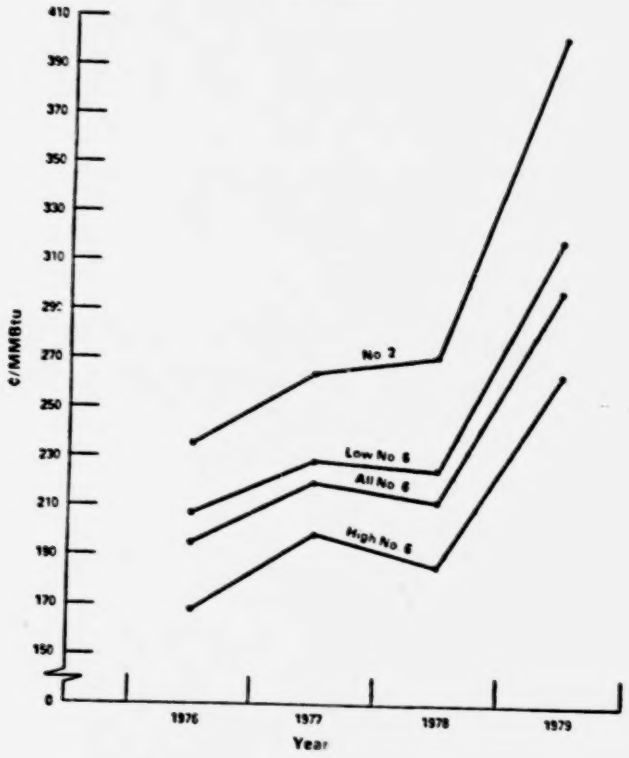
3/ The price data for coal is the same as shown under FPC Form No. 423 price data.

4/ Mathematically the price difference ratio is $\frac{P_2 - P_1}{P_1}$, where P_2 = The price of fuel oil or coal and P_1 = the price of natural gas. The ratio indicates the percent difference between natural gas and alternate fuel prices. For example in January 1980 electric utilities reported that in that month they paid 1.847 times more (184.7 percent) for No. 2 fuel oil than they paid for natural gas.

APPENDIX B
CHART I

Comparison of Fuel Oil Prices 1/

(1976 - 1979)



Source Form No 423

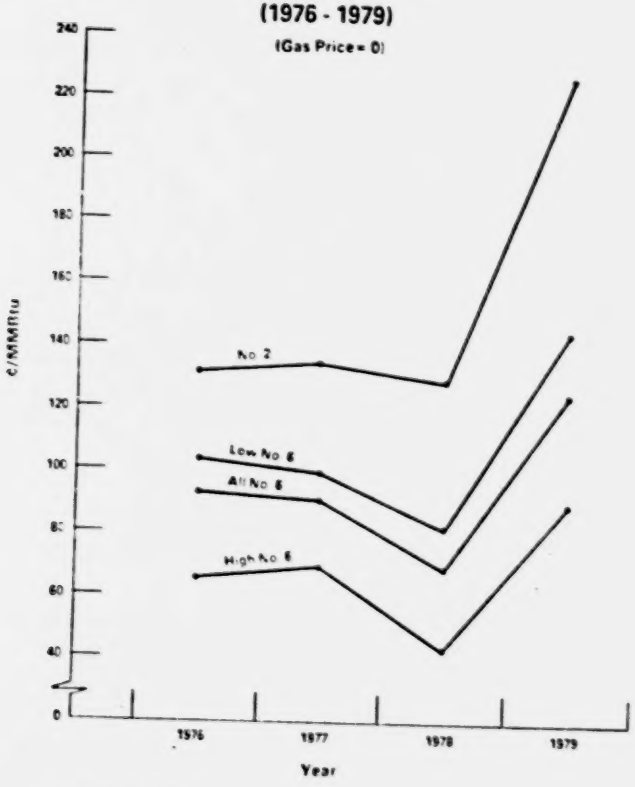
1/ Annual average prices as shown in Appendix A

APPENDIX B
CHART 2

Price Difference Between Fuel Oil & Natural Gas Prices 1/

(1976 - 1979)

(Gas Price = 0)



Source: Form No. 423

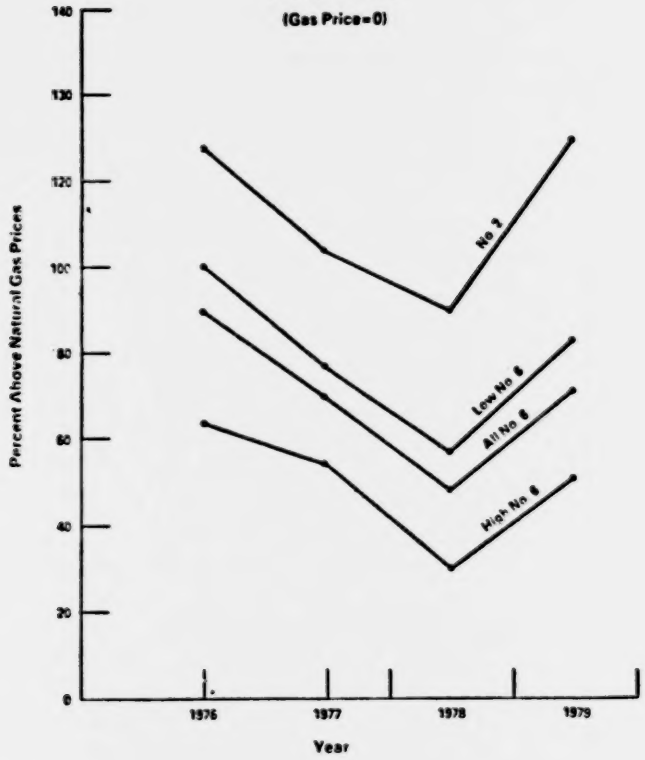
1/ Based on average annual prices as shown in Appendix A

APPENDIX B
CHART 3

Percentage Difference Between Fuel Oil & Natural Gas Prices[1/]

(1976 - 1979)

(Gas Price=0)



Source Form No 423

1/ Based on annual average prices as shown in Appendix A.

Appendix C

The tables and text contained in this appendix were taken from the Environmental Assessment of the Determination of Alternative Fuels for Essential Agricultural Users, Docket No. RM79-40, issued June 3, 1980.

TABLE 1

COMPARISON OF U.S. REGIONAL AND TOTAL CONSUMPTION BY ALL USERS WITH DELIVERIES AND CURTAILMENTS TO LARGE INTERSTATE ESSENTIAL AGRICULTURAL USERS (APRIL 1978 THROUGH MARCH 1979)
(Billion Cubic Feet)

DOE REGION	TOTAL GAS CONSUMPTION (1978) 1/	ESSENTIAL AG. GAS DELIVERIES 2/	ESSENTIAL AG. GAS CURTAILMENTS 2/
1. New England	262.8	2.7	0.9
2. New York New Jersey	798.5	17.7	10.2
3. Mid-Atlantic	1,142.1	34.3	11.6
4. South Atlantic	1,634.1	105.9	53.3
5. Midwest	4,019.0	155.5	33.9
6. Southwest	7,665.3	58.3	5.8
7. Central	1,279.5	110.6	25.7
8. North Central	620.8	16.6	7.3
9. West 4/	1,802.7	63.9	2.8
10. Northwest	402.7	22.2	0.2
U.S. TOTAL	19,627.5	587.7	151.5

Note: U.S. TOTAL may not equal the sums of columns due to rounding.

1/ Source: "Natural Gas Production and Consumption: 1978", DOE/EIA, Energy Data Reports, Natural Gas Annual, October 12, 1979, Table 6, p. 7.

2/ Source: EIA 50, April 1978 - March 1979, with two digit SIC's weighted to obtain essential agricultural user volumes. SIC 4971, Irrigation Systems, is excluded. For weighting coefficients, see Appendix B.

3/ Natural gas volumes for Arkansas, Louisiana, Texas, New Mexico, and Oklahoma weighted for interstate gas. For weighting coefficients, see Appendix B.

4/ Natural gas volumes for Hawaii not included.

5/ Natural gas volumes for Alaska not included.

TABLE 2

INTERSTATE DELIVERIES AND CURTAILMENTS WITH ALTERNATE FUELS USED BY LARGE ESSENTIAL AGRICULTURAL USERS, APRIL 1978 - MARCH 1979[1/]
(Billion Cubic Feet)

DOE Region	Del.	Curt.	Alternate Fuel				
			Dist.	Resid.	Coal	Propane	Other
1. New England	2.7	0.9	0	0.8	0	0	0.1
2. New York/ New Jersey	17.7	10.2	2.8	6.7	0	0.5	0.2
3. Mid-Atlantic	34.3	11.6	2.0	6.7	1.0	0.2	1.7
4. South Atlantic	105.9	53.3	15.2	16.0	3.9	2.5	15.7
5. Midwest	155.5	33.9	7.8	17.0	4.1	2.0	3.0
6. Southwest[2/]	58.3	5.8	0.9	4.0	0.3	0.1	0.5
7. Central	110.6	25.7	10.2	7.1	6.0	1.0	1.4
8. North Central	16.6	7.3	1.1	4.0	1.8	0.2	0.2
9. West[3/]	63.9	2.8	1.5	0.3	0.7	0.1	0.2
10. Northwest[4/]	22.2	0.2	0	0.1	0	0	0.1
U.S. Total	587.7	151.5	41.6	62.7	17.8	6.6	22.8

Note: U.S. Totals may not equal the sums of columns due to rounding.

1/ Source: EIA 50, April 1978 - March 1979, with two-digit SIC's weighted to obtain essential agricultural user volumes.

2/ Natural gas volumes for Louisiana, Arkansas, Texas, New Mexico, and Oklahoma weighted for interstate gas.

3/ Natural gas volumes for Hawaii not included.

4/ Natural gas volumes for Alaska not included.

D. Socioeconomic Impact

Examination of the socioeconomic impact of denying Priority 2 curtailment protection to essential agricultural users has centered on the effect fuel cost changes would have on production costs. Nationally, the cost impact is small. An analysis of EIA 50 data shows that 20.5 percent of natural gas demand by essential agricultural users was curtailed between April 1978 and March 1979. Curtailed volumes were replaced by alternative fuels in the following proportions:

	Percent
Residual	41.4
Distillate	27.4
Coal	11.8
Propane	4.4
Other Fuels	1.9
None	13.1

Fuel cost impact varies considerably in different regions. Table 5 presents the regional prices for natural gas and alternative fuels used to calculate the price differentials in table 6. (A detailed explanation of the fuel price data and methodology used by the staff in this analysis appears in appendix C.) Column 1 of table 7 shows the estimated change in total fuel costs if large essential agricultural users in each region are denied Priority 2 curtailment protection. These figures suggest that absolute fuel costs would increase considerably, the largest increase being $82 million in DOE's Region 4, the South Atlantic states. However, these absolute figures are more meaningful when compared to the size of the industrial/essential agricultural base that would be affected. Column 2 shows the value added in manufacture by essential agricultural users in each of the 10 DOE regions. Column 1 can be divided by column 2 to show the percentage change in total cost resulting from the curtailment of essential agricultural users. Column 3 places the fuel cost increases of column 1 in better perspective by showing that production costs would only increase by 0.23 percent nationally. The greatest impact would occur in Regions 4 (0.60 percent) and 7 (0.61 percent).

Appendix C shows regional cost impacts further broken down by individual SIC codes. This analysis shows that production cost impacts might exceed 1 percent in some instances.

TABLE 5

REGIONAL FUEL PRICES FACING Essential Agricultural Users
(In $/million Btu; March 1980)1/

DOE Region	Natural Gas	Distillate	Residual	Coal	Propane
1. New England	3.32	----2/	3.89	----	6.13
2. New York/New Jersey	3.26	5.65	4.92	----	5.65
3. Mid-Atlantic	3.38	6.36	4.63	1.65	5.91
4. South Atlantic	2.32	6.18	3.61	1.49	6.09
5. Midwest	2.59	6.38	3.93	1.27	5.91
6. Southwest	2.19	4.81	3.76	1.20	4.47
7. Central	2.13	6.73	3.40	1.24	6.34
8. North-Central	3.34	5.75	3.68	0.51	6.60
9. West	3.05	6.71	4.05	0.96	6.27
10. Northwest	4.01	NA3/	NA	----	NA
U.S. Weighted Average	2.56	6.24	3.91	1.24	6.03

1/ January prices are from Energy Data Report, Cost and Quality of Fuels for Electric Utility Plants, January 1980. These prices are indexed to March 1980 by the Producers Price Index (PPI) for each fuel. The price of propane is set equal to the price of No. 2 fuel oil for each state in January 1980 and indexed to March 1980 by the PPI for propane.

2/ None of this fuel type was burned by essential agricultural users as an alternative fuel in these regions.

3/ The Region 10 prices designated by "NA" are not available. Therefore, the national average price differential from table 6 was used to calculate the regional impact.

TABLE 6

REGIONAL PRICE DIFFERENTIALS[1/]
(Alternative Fuel Price Minus Natural Gas Price)
($/million Btu's; March 1980)

DOE Region	Distillates	Residuals	Coal[2/]	Propane
1. New England	----	0.57	----	2.81
2. New York/New Jersey	2.39	1.66	----	2.39
3. Mid-Atlantic	2.98	1.25	(1.73)	2.53
4. South Atlantic	3.86	1.29	(0.83)	3.77
5. Midwest	3.79	1.34	(1.32)	3.32
6. Southwest	2.62	1.57	(0.99)	2.28
7. Central	4.60	1.27	(0.89)	4.21
8. North-Central	2.41	0.34	(2.83)	3.26
9. West	3.66	1.00	(2.09)	3.22
10. Northwest	2.23	1.35	----	3.47
U.S. Weighted Average	3.68	1.35	(1.32)	3.47

1/ Derived from table 5.

2/ (·) means that coal is less expensive than natural gas by the amount bracketed.

TABLE 7

PERCENTAGE CHANGE IN TOTAL PRODUCTION COSTS
CAUSED BY AGRICULTURAL EXEMPTION
(SIC 20 through 39 only)

DOE Region	Total Cost Impact[1/] (In $000)	Value Added by Essential Agricultural Users[2/] (In $000,000)	Cost Difference (Percent)
1. New England	485.5	9,597.7	0.01
2. New York/New Jersey	18,360.0	10,279.7	0.18
3. Mid-Atlantic	12,893.6	10,747.3	0.12
4. South Atlantic	82,145.9	13,710.1	0.60
5. Midwest	53,399.0	26,263.5	0.20
6. Southwest	8,166.8	2,391.2	0.34
7. Central	45,722.8	7,511.1	0.61
8. North-Central	(770.2)	1,945.5	(0.04)
9. West	6,040.3	11,963.2	0.05
10. Northwest	244.7	2,987.2	0.01
U.S. Totals	226,688.4	97,396.5	0.23

1/ Derived by multiplying the alternative fuel figures for each region by the corresponding price differential between natural gas and the alternative fuel. These numbers also include the fuel cost saving associated with switching from natural gas to coal.

2/ Value added data are from the Annual Survey of Manufacturers Statistics for States, SMSA's, Large Industrial Counties and Selected Cities, 1976. These figures are weighted to include only essential agricultural users and are indexed by the Producers Price Index to March 1980.

The overall impact on affected agricultural users appears insignificant because of the small likelihood that large increases in production cost will occur. Notwithstanding this fact, the response of any individual essential agricultural users to increased energy costs can not be predicted. The major options for a business faced with the prospect of rising costs, other than going out of business, are to pass cost increases along in its product price, to absorb the cost increase by reducing profits, or to conserve. These options could have varying effects on production and employment of a particular business with resulting socioeconomic effects.

TABLE 9

REGIONAL FUEL COST IMPACT CAUSED BY SWITCHING TO ALTERNATIVE FUELS 1/
(In $000)

Region	Alternative Fuels				Combinations		
	Distillates	Residual	Coal	Propane	Residual/Coal	Residual/Coal/Propane	All
1. New England	0	472	0	14	472	486	486
2. New York/New Jersey	6,721	11,139	0	1,109	11,316	12,439	19,160
3. Mid-Atlantic	5,990	8,423	(1,796) 2/	488	6,627	7,115	13,105
4. South Atlantic	58,541	20,579	(3,206)	9,527	17,374	26,901	85,442
5. Midwest	29,422	22,781	(5,411)	6,756	17,369	24,127	53,549
6. Southwest	2,353	6,222	(318)	180	5,904	6,084	8,437
7. Central	47,053	9,041	(5,318)	4,134	3,724	7,858	54,911
8. North-Central	2,740	1,366	(5,035)	528	(3,668)	(3,140)	(400)
9. West	5,545	279	(1,549)	383	(1,270)	(887)	4,658
10. Northwest	83	154	0	7	154	161	243
U.S. Total	158,447	80,455	(22,631)	23,321	57,822	81,143	239,592

1/ Cost impact data for all SIC's are included in this table. Data for SIC's 1, 2, 7, 14, 42, 51, and 54 were not included in table 7, where percentage change in total production costs were identified, because "value added" data were lacking. However, the missing SIC's account for only 6.6 percent of the total fuel cost impact.

2/ ( ) indicates a fuel cost saving.

Appendix C—Fuel Price and Production Cost Impact Methodologies

Fuel Prices

The decision to use fuel prices faced by steam-electric utilities, contained in EIA Energy Data Reports, was based on three main factors:

1. Steam-electric utility data as the best available data which provide a consistent base of prices to determine the price differentials. These price differentials are preferable to price differentials derived from a number of potentially inconsistent sources or data bases.
2. EIA's steam-electric fuel price provides regional data.
3. The prices are fairly recent, minimizing the need for an index.

The major problem with the data is the lack of prices for some states. *Energy Data Report, Cost and Quality of Fuels for Electric Utility Plants, January 1980* provides prices for natural gas, coal, distillate, and residual fuel oils for most states. Major states with no reported data were:

Natural gas—Maryland, North Carolina, and Tennessee.
Distillate—New York and Region 10.
Residual—Iowa, Kansas, North Carolina, Alabama, Kentucky, Tennessee and Region 10.

In these instances, the regional price was calculated without considering the missing states. Since January data were not available in some cases, December 1979 prices were escalated to March 1980 using the Producer Price Index for natural gas in Massachusetts and for distillate fuels in Minnesota, Montana, and New Jersey. Distillate prices may be slightly low for Regions 6 and 8 because of what appear to be low prices for Arkansas and Montana. Thus, the impact may be slightly understated.

The Energy Data Reports do not contain propane prices, and in other sources, regional prices are not available. Since there is some indication of a long-term equivalency between the prices of distillate fuel oil and propane, the staff set the propane price equal to the January 1980 price of distillates for each region. The January prices were then escalated to the March 1980 level using the Producer Price Index for Propane.

Regional prices were derived from the available state prices by weighting each price according to its percentage of the particular fuel consumed by essential agricultural users in that region. For example, 64 percent of the curtailment in Region 3 was in Pennsylvania. Thus, a weight of 0.64 was applied (the sum of the weights = 1.00). Similarly, Pennsylvania consumed 72 percent of all residual oil used as an alternative fuel. Thus, a weight of 0.72 was applied. EIA 50 reports that large essential agricultural users in Pennsylvania did not use any coal as an alternative fuel. Thus, a weight of 0 was applied. By applying these weights, the staff determined an average regional price for each fuel type in January 1980. The Producers Price Index for each fuel type was then used to index the prices from January to March 1980, making the prices as current as possible.

Production Cost Impact Analysis

The regional prices were applied to the alternative fuel figures generated from EIA 50 (See table 2.) to convert the natural gas replacement volumes into dollars (i.e., production costs). The results can be seen on table 7, column 1.

Table C–1 is similar to table 7, column 1, except that it shows the total regional impact in production costs manufacturing SIC codes. Table C–1 shows that the total production cost impact would be greatest in Region 4, SIC 20 and 28; Region 5, SIC 20; and in Region 7, SIC 20. The impact to production costs in these regional/SIC combinations totals about 58 percent of the nationwide impact.

Table C–2 shows value added figures by region from the Annual Survey of Manufacturers for each manufacturing SIC Code. The data from tables C–1 and C–2 enabled the staff to determine the impact on production costs for each region and manufacturing SIC code. The results are shown in table C–3.

Essential agricultural users in SIC code 32 (Stone, Clay, and Glass) would be most adversely affected (0.75 percent) by denying Priority 2 exemption.

Table C-3 shows that the cost impact would exceed 1 percent in seven instances: Region 6, SIC 26—3.37 percent; Region 4, SIC 32—2.40 percent; Region 4, SIC 28—1.64 percent; Region 7, SIC 32—1.64 percent; Region 2, SIC 32—1.48 percent; Region 4, SIC 26—1.18 percent; and Region 8, SIC 28—1.12 percent.

TABLE C-1

REGIONAL TOTAL COST IMPACT BY SIC
(In $000's)

DOE Region	SIC Codes								
	20	21	22	24	26	30	31	32	34
1. New England	393.9	----	1.1	15.4	185.1	0	----	0	0
2. New York/New Jersey	7,978.3	----	17.9	168.5	1,561.5	0	----	8,615.7	28.7
3. Mid-Atlantic	9,642.0	96.4	28.0	137.6	2,013.8	395.0	----	672.3	157.0
4. South Atlantic	26,629.9	518.2	722.6	6,754.8	15,340.2	1,622.2	181.0	11,868.0	773.1
5. Midwest	39,316.5	115.9	6.5	5,008.6	4,221.1	501.3	586.9	4,196.6	650.0
6. Southwest	1,629.1	----	0	2,205.8	6,256.0	75.0	----	(5.3)[1/]	15.9
7. Central	32,785.0	----	----	185.7	8,105.0	282.6	----	5,182.5	1,383.0
8. North-Central	(48.1)	----	----	3.6	588.7	78.6	38.6	(851.5)	19.6
9. West	3,136.6	----	9.1	259.0	1,165.9	139.1	0	860.0	95.7
10. Northwest	180.2	----	0	46.5	60.6	----	----	9.6	0
U.S. Total	121,757.6	778.6	782.8	15,060.0	55,508.9	3,010.6	715.1	30,495.9	3,142.9

U.S. Total for All Regions and All SIC's = 234,686.6

1/ Derived by multiplying the alternative fuel figures for each SIC code by the corresponding price differential between natural gas and the alternative fuel in table 6.

2/ Includes fuel cost saving associated with switching from natural gas to coal

TABLE C-2

VALUE ADDED FOR ESSENTIAL AGRICULTURAL USERS[1/]
(In $ millions)

DOE Region	SIC Codes								
	20	21	22	26	28	30	31	32	34
1. New England	2,084.9	----	912.6	1,014.0	551.9	1,764.2	----	554.1	5,213.3
2. New York/New Jersey	6,493.8	----	12.8	249.1	2,283.0	188.2	----	567.6	685.9
3. Mid Atlantic	7,178.6	238.3	21.6	651.7	1,682.7	162.5	276.6	565.0	685.2
4. South Atlantic	9,157.4	519.2	133.6	570.5	2,036.5	270.3	516.1	496.5	528.2
5. Midwest	18,752.4	----	3.6	581.7	2,765.2	702.3	116.2	958.7	2,396.7
6. Southwest	1,625.1	----	----	69.3	538.2	64.4	----	61.7	76.4
7. Central	6,078.5	----	----	62.9	860.6	117.0	----	193.1	219.0
8. North Central	1,767.7	----	----	5.7	53.6	----	----	94.9	43.9
9. West	8,492.2	----	3.3	168.9	755.9	1,672.4	47.6	353.1	469.8
10. Northwest	2,509.2	----	4.1	158.6	197.3	----	----	35.3	83.8
SIC Totals	64,118.8	757.5	1,091.5	3,528.4	11,704.7	4,421.5	956.5	3,858.0	7,999.7

U.S. Total for All Regions and All SIC's = 97,398.5

1/ Value Added data are from the Annual Survey of Manufacturers-Statistics for States, SMSA's, Large Industrial Counties, and Selected Cities, 1976. These figures are weighted to include only essential agricultural users and are indexed by the Producers Price Index to March 1980.

TABLE C-3

PERCENTAGE CHANGE IN TOTAL PRODUCTION COSTS
CAUSED BY ALTERNATIVE 1 REVISION
(by Region and SIC)

DOE Region	SIC Codes								
	20	21	22	26	28	30	31	32	34
1. New England	0.01	----[1]	0[2]	0	0.03	0	----	0	0
2. New York/New Jersey	0.08	----	0.14	0.16	0.07	0	----	1.48	0.01
3. Mid-Atlantic	0.13	0.04	0.13	0.02	0.12	0.24	----	0.11	0.03
4. South Atlantic	0.29	0.10	0.54	1.18	1.64	0.60	0.02	2.40	0.15
5. Midwest	0.21	----	0.18	0.52	0.15	0.07	0.50	0.46	0.02
6. Southwest	0.10	----	0	3.37	0.79	0.19	----	(0.01)[3]	0.02
7. Central	0.56	----	----	0.31	0.96	0.17	----	1.66	0.59
8. North-Central	(0.04)	----	----	0.04	1.12	----	----	(0.88)	0.04
9. West	0.04	----	0.22	0.15	0.16	0.01	----	0.24	0.02
10. Northwest	0	----	0	0.06	0.02	----	----	0.05	0
U.S. Totals	0.19	0.10	0.07	0.37	0.47	0.07	0.08	0.75	0.06

U.S. Total for All Regions and All SIC's = 0.23

1/ EIA 50 reported no data or the Annual Surveys of Manufacturers reported that no value added figures were available.

2/ "0" means less than 0.005 percent.

3/ ( ) denotes a fuel cost saving.

¶ 32,070 Exemption From Incremental Pricing for Distillers Who Produce Fuel Grade Alcohol Blended to Form Gasohol

45 F. R. 40617 (June 16,1980).

18 CFR Part 282

[Docket No. RM80-64]

Exemption From Incremental Pricing for Distillers Who Produce Fuel Grade Alcohol Blended To Form Gasohol

Issued: June 9, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it is proposing to adopt a rule, pursuant to Section 206(d) of the Natural Gas Policy Act of 1978, which will grant a four-year incremental pricing exemption for distillers who use natural gas to produce anhydrous alcohol to be blended with gasoline to form gasohol. To qualify for the exemption the distillation facility must have been in existence on or before May 9, 1980, and must not have had the installed capability to lawfully burn coal. The notice is being issued in response to a suggestion that the Commission offer incentives to industrial facilities which distill gasohol and to pursue the question of whether the exemption is in the public interest and should be granted.

DATE: Written comments by July 18, 1980. Request to participate in hearing by July 15, 1980. Hearing date: July 22, 1980.

ADDRESS: Written comments and request to participate to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM80-64).

HEARING LOCATION: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8400.

SUPPLEMENTARY INFORMATION:

I. Introduction

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires the Federal Energy Regulatory Commission to promulgate regulations under which interstate pipelines and their local distribution company customers must channel a specific portion of acquisition costs of natural gas to industrial users.

In the course of developing the rules for Title II and from the comments received from the implementation of our Regulations under Title IV [1] of the NGPA, numerous parties [2] suggested that the Commission offer incentives to industrial facilities which distill "gasohol." One specific recommendation to the Commission is to allow, in appropriate circumstances, an exemption from incremental pricing for those distillers who produce anhydrous alcohol for use as gasohol. Distillers, through their comments, stated that they have idle capacity which they believe can and should be used to produce anhydrous alcohol, a component of gasohol. A distiller must retrofit or redesign his plants in order to produce anhydrous alcohol because it is necessary to increase the proof level

[1] See Docket No. RM79-40, *Interim Rule—Determination of Alternative Fuels for Essential Agricultural Users.*

[2] Among those expressing interest in furthering the distillation of "gasohol" were eighteen members of the United States Senate.

from 160 proof for beverage alcohol to approximately 200 proof for fuel grade alcohol. Before they will make the capital investment to retrofit their plants, distillers allege they need an assured energy source at an economic price.

In response to these suggestions, the Commission hereby issues a Notice of Proposed Rulemaking in Docket No. RM80-64 for the purpose of pursuing the question of whether such an exemption would be in the public interest and therefore should be granted. Should the Commission determine such an exemption is appropriate, it would, pursuant to section 206(d) of the NGPA,[3] submit a final exemption rule to Congress. If neither house disapproves the rule, it would then take effect.

II. Proposed Rule

The Federal Energy Regulatory Commission is proposing a rule which would grant a four-year incremental pricing exemption for the use of natural gas in the distillation of fuel grade alcohol from Wood grains and biomass. To be eligible for the exemption, the facility must have been in existence on or before May 9, 1980 and must not have the installed capability to lawfully burn coal.

Most distilleries are equipped to burn natural gas and use oil for backup fuel. In some cases the distilleries are capable of burning coal, but coal's major drawback as an energy source is that it creates air pollution problems which possibly violate EPA rules.

The comments [4] alleged that fuel oil used in the production of distilled spirits is twice as expensive as natural gas. To be competitive in the market place, distillers require an energy source that is as economical as natural gas. The proposed rule specifically prohibits a distiller who currently is physically capable and legally authorized to burn coal from enjoying an incremental pricing exemption for any use of natural gas.

The objective of this rule is to support the National 1980–1981 Alcohol Fuels Production Program by making it easier for idle capacity to be utilized to produce fuel grade alcohol.[5] The Commission recognizes that various other legislative initiatives have or may be enacted to spur alcohol fuel production. However, these may take a year or more to actually affect production. The present rule is proposed in the belief that it would encourage investment and production to begin almost immediately and thus speed up the achievement of the national gasohol objectives. Public comment on the validity of this view is solicited.

The rule would exempt only those facilities which were in existence as of May 9, 1980. Considering the national end use energy policy, the Commission does not believe it appropriate for any new boiler fuel facilities to use natural gas as the primary energy source. Therefore, exemptions would be limited to existing facilities for which the alternative fuel would be oil.

On the other hand, while production would be encouraged in the short-run, the "sunset" provision of the proposed rule avoids any conflict with our long-run goal to encourage facilities to switch to coal or other renewable energy sources. Under the sunset provision, the

[3] Section 206

(d) Other Exemptions.—

(1) In General.—The Commission may, by rule or order, provide for the exemption, in whole or in part, of any other incrementally priced industrial facility or category thereof from the rule prescribed under section 201 (including any amendment under section 202 to such rule).

(2) Congressional Review.—Any rule which provides for any exemption under this subsection may take effect after the expiration of the first 30 calendar days of continuous session of Congress (determined in accordance with section 507(b)) after a copy of such rule has been submitted to each House of the Congress, unless, during such 30 day period of continuous session of Congress, either House of the Congress adopts a resolution of disapproval described in section 567(c)(3), with respect to such rule.

[4] See comments filed by Distilled Spirits Council of the United States, Inc., filed September 28, 1979, Docket No. RM79-40.

[5] In April 1979, the President, in a nationwide television speech, emphasized the need for this

incremental pricing exemption will expire no later than May 9, 1984.[6]

A. The Public Policy Standard

This rule is proposed in the belief that it would advance several policy objectives.

The demand for premium fuels cannot be met from traditional domestic sources. As these domestic sources of supply are being depleted, our country has had to increase its purchase of imported fuels. The last few years have exposed the instability and economic vulnerability of such reliance.

In Order No. 30,[7] the Commission recognized the danger of increased reliance upon imported fuel oils. The Commission considered the alternative of increasing distillate oil stocks by reducing gasoline production, thereby allowing refineries to increase distillate production. The Commission rejected this approach stating:

> * * * Induced shortages of gasoline could create serious dislocation in the transportation sector of our economy because of its virtually total dependence upon liquid hydrocarbons. If other potentially effective means of increasing distillate supplies are seen to exist without equivalent risk or harm to the public welfare they should be fully utilized. The public interest lies in a balanced set of strategies and actions for coping with the fuel emergency.[8]

Because the transportation sector accounts for over one-half of total national petroleum consumption,[9] gasoline consumption substantially affects the amount of U.S. crude oil imports. Consequently, gasohol, as a motor fuel extender, offers a reasonable means of reducing our level of imports.

Energy efficiency arguments have frequently been made against large-scale production of fuel grade alcohol. According to some studies, more energy is expended to produce a gallon of fuel grade alcohol than is contained in the gallon itself. The end result is a "net energy loss." The Commission recognizes the importance of this issue and seeks data on its empirical importance. Commenters are also invited to address the question of how, if at all, the Commission should factor the net energy issue into policy decisions.

It may be in the Nation's interest to accept conversion losses in order to extend the potential of future gasoline supplies. The Commission seeks public data, comments and views on the fundamental policy question of how to evaluate the increased public policy considerations attendant to a choice between a net energy loss and obtaining more transportation grade fuel supplies.[10]

An additional area of debate revolves around the view that gasohol already enjoys numerous subsidies and needs no further financial incentives. Within the last two years Congress has enacted at least four laws to encourage the production of gasohol. These are (1) Energy Tax Act of 1978 (Pub. L. 95–618), (2) Surface Transportation Assistance Act of 1978 (Pub. L. 95–599), (3) Food and Agricultural Act of 1977 (Pub. L. 95–113), and (4) Crude Oil Windfall Profit Tax Act of 1980 (Pub. L. 96–817). Comments on the adequacy of the incentives provided by these and any other pertinent programs are requested.

Because of the substantial and unresolved controversies over public policy toward gasohol, the Commission requests respondents to devote particular attention to these and any other issues relevant to deciding whether the public interest is best

country to increase its use of gasohol. In May, the President proposed the White House Rural Development Initiatives which was to develop alternate energy sources, including gasohol.

[6] The Commision realizes that the Section 202 (Phase II exemption may be meaningless with the recent Congressional veto. But the proposed rule would also apply to section 201 (Phase I) of Title II and the exemption would expire four years from the May 9, 1980 date.

[7] 10 C.F.R. Parts 3 and 284, issued May 25, 1979 (Docket No. RM79–34, 44 FR 30323).

[8] *Supra.*, note 5.

[9] The Report of the Alcohol Fuels Policy Review, DOE PE–0012, U.S. Department of Energy, page 3, June 1979.

[10] The generation of electricity also has an input-output Btu ratio of less than one. However, the public interest clearly requires continued reliance upon this energy forum.

served by exemption from Title II of the NGPA existing distilleries which produce fuel grade alcohol to blend with gasoline.

III. Comment Procedures

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80–64. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, July 18, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. Public Hearing.

A public hearing on this proposed rule will be held on July 22, 1980, beginning at 10:00 a.m. EST at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing. Interested persons may also obtain this information by calling the Office of the Secretary of the Commission.

Request to participate in the hearing should be directed to the Secretary of the Commission at the above address, no later than seven days prior to the hearing. Requests should reference Docket No. RM80–64, and should indicate (1) the amount of time required, but not to exceed 15 minutes for oral presentation, and (2) the telephone number at which the persons making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Office of Public Information three days before the hearing will also be available at the Commission on the morning of the hearing.

The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of the individual making the statement. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available in the public file for this proceeding, Docket No. RM80–64 in the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

Section 282.203 is amended by adding a new paragraph (f) to read as follows:

§ 282.203 Exempt end-users.

* * * * *

(f) All gas used until May 9, 1984, in the distillation of fuel grade alcohol from food grains or biomass by facilities in existence on May 9, 1980, which do not have the installed capability to burn coal lawfully.

¶ 32,071 Regulations Governing Safety of Water Power Projects and Project Works

45 F. R. 41608 (June 19, 1980).

18 CFR Parts 3 and 12

[Docket No. RM80-31]

Regulations Governing Safety of Water Power Projects and Project Works

June 16, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it proposes to adopt regulations governing the safety of water power projects and project works licensed under Part I of the Federal Power Act. The proposed regulations consolidate under Part 12 those portions of the Commission's current dam safety program that were initiated by case specific Commission orders, and revises the existing dam safety inspection regulations.

DATE: Written comments by August 1, 1980.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Reference Docket No. RM80-31.

FOR FURTHER INFORMATION CONTACT:

Glenn Berger, Office of the General Counsel, Federal Energy Regulatory Commission, Room 3331-A, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8364.

Howard Jack, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8608-C, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8448.

Ron Corso, Office of the General Counsel, Federal Energy Regulatory Commission, Room 440, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4868.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) proposes to revise its regulations governing the safety of all water power projects and project works licensed or required to be licensed under Part I of the Federal Power Act (Act).[1] The proposed rulemaking consolidates the Commission's Orders, regulations and practices relating to dam safety under Part 12 of the Commission's regulations.

Background

The Federal Energy Regulatory Commission licenses water power projects that are developed by non-Federal entities including individuals, private entities, states, municipalities, electric cooperatives, and others. A license is required if a project is located on navigable waters or lands of the United States; or uses surplus water or water power from a government dam; or has had significant construction after 1935, is located on non-navigable waters over which Congress has jurisdiction under the commerce clause, and affects the interests of interstate or foreign commerce.

At the end of 1979, the Commission had under its jurisdiction 1,181 dams of all sizes and hazard classifications, including those for which applications for license were pending.

Under section 10(c) of the Act, the licensee of any water power project within the jurisdiction of the Commission must conform to any regulations that the Commission "may from time to time prescribe for the protection of life, health, and property."[2]

[1] The terms "project" and "project works" have the same meaning as defined in §§ 3(11) and 3(12) of the Federal Power Act.

[2] 16 U.S.C. §803(c)(1976).

In addressing its responsibility under section 10(c) of the Act the Commission has developed procedures to ensure quality in design, construction, operation, and maintenance of water power projects.

The Commission staff reviews designs before the construction of a licensed project. During the construction of a project, the regional offices conduct periodic inspections, usually monthly. Furthermore, the Commission often required, in the terms and conditions of a license for an unconstructed project, that the licensee appoint a board of independent consultants subject to the Commission's approval. The board usually consists of three members with geotechnical, civil engineering, design, and construction expertise. The board acts in an advisory capacity during the construction of the project. Once a water power project becomes operational, members of the Commission staff conduct an annual review of the project's operating history and compliance with licensing conditions, and inspect the project works.

The Commission also requires all licensed projects and any project for which a license is pending to implement, and modify when appropriate, an emergency action plan. The plan must be designed to provide an early warning to upstream and downstream inhabitants, property owners, and recreational users in case of an impending or actual sudden release of water caused by failure of any project structure.

On December 27, 1965, the Commission's predessor agency, the Federal Power Commission (FPC), provided in Order No. 315 [3] for complete safety inspections of licensed water power project works by independent consultants at five-year intervals of more frequently, if necessary. The existing Part 12 regulations under FPC Order No. 315 are applicable only to these licensed projects that have a dam exceeding 35 feet in height above the streambed or a gross storage capacity of more than 2,000 acre-feet. The inspection provisions established by Order No. 315 were designed to supplement the staff's inspection of all project works with detailed periodic safety inspections supervised by an independent consultant.

Dam failures in the 1970's, notably the failure of Teton Dam (U.S. Department of Interior, Water and Power Resources Service), and the Taccoa Falls Dam in Georgia, demonstrated a need to review Federal and non-Federal dam safety practices and procedures. Pursuant to President Carter's directive on April 23, 1977, Federal review was initiated by several Federal agencies to ensure the structural integrity of project works and to establish well-conceived plans to protect life and property if an emergency should occur as a result of a dam failure or accident causing a sudden release of water.[4]

[3] Inspection of project works with respect to safety of structures, 18 C.F.R. Part 12 (1979).

[4] According to the President's directive, the Chairman of the Federal Coordinating Council for Science, Engineering and Technology (FCCSET) was to preside over the preparation of Federal dam safety guidelines. The Director of the Office of Science and Technology Policy (OSTP) would then establish a committee of experts to review the proposed procedures and policies. Three significant documents have been produced through the interagency review of dam safety practices initiated by the President in 1977. In November 1977, FCCSET issued a report entitled *Improving Federal Dam Safety* followed by the *Federal Dam Safety Report of the OSTP Independent Review Panel* in December 1978. FCCSET published its *Federal Guidelines for Dam Safety* on June 25, 1979. Finally, the President requested that each department and agency report to the Director of the Federal Emergency Management Agency (FEMA) concerning the progress made toward implementing the guidelines. The Chairman of the FERC transmitted the Commission staff's report to FEMA on February 1, 1980. The FERC report showed substantial prior compliance with the guidelines.

The government-wide review of dam safety practices has produced new studies and guidelines. The Secretary of the Interior requested the National Research Council to review the dam safety program of the Water and Power Resources Service (formerly the Bureau of Reclamation). The Congress in 1972 enacted the National Dam Inspection Act (33 U.S.C. §§ 467-467e (1976)) authorizing the Secretary of the Army to inspect certain non-Federal dams except those licensed by FERC.

The Commission had already begun extensive review of its dam safety policies and procedures at the time of the Walter Bouldin Dam failure on February 10, 1975 (FERC Project No. 2146). Emergency action plans and dam safety inspections were standard parts of the Commission's program at the time. However, during the period of review the Commission determined that it was advisable to consolidate the various regulations, orders, and practices relating to dam safety in the Commission's regulations.

The proposed rule in this docket would consolidate under Part 12 those portions of the current dam safety program that were initiated by case-specific Commission orders and revise the existing dam safety inspection regulations.

The proposed rulemaking continues to require dam inspections every 5 years by an independent consultant. However, the qualifications of an independent consultant are defined to avoid conflicts of interest. Furthermore, the category of dams which are required to have inspections every five years is expanded. Emergency action plans are now included under Part 12. The proposed rule, in order to cooperate with the President's directive and conform to the *Federal Guidelines for Dam Safety*,[5] includes improved inspection requirements, and criteria for review, design, construction, and testing of project works, monitoring quality control and assurance, and solicitation of public cooperation on matters related to the protection of life, health, and property at licensed projects.

The Commission also proposes to amend Part 3 by revising Subpart B to include a description of staff investigatory practices.

Policy

The *Federal Dam Safety Report* of the OSTP Independent Review Panel states that *"perhaps the most fundamental principle of dam safety is recognition that every dam runs some risk of failure.* This principle is so elementary that its significance is easily overlooked."[6] There is "incomplete understanding of or uncertainties associated with natural (earthquakes and floods) and man-made (sabotage) destructive forces, with materials' behavior and response to these forces, and in control of the construction process."[7] The report noted that dam engineering is not an exact science, but rather an art that must deal with the complexities of site selection, design, construction, the aging process of any structure, and foreseeable and unforeseeable natural phenomena. The Commission believes that, given these complexities, the builders and the operators of both Federal and non-Federal water power projects have enjoyed an uncommonly high degree of success. Nevertheless, if a dam fails, whether due to human error or unforeseeable natural events, the magnitude of the destruction of lives and property that follows can be awesome. While the licensee has the basic responsibility for the protection of life and property, it is the policy and the responsibility of this Commission to ensure that licensees carry out those responsibilities to avert such tragedies and assure a continued awareness of acceptable dam safety practices.

There are two overriding Federal interests in the regulation of water power projects. First, the development and maintenance of a reliable source of power that is based on a renewable resource is a matter of national priority. Secondly, the development of facilities to generate that power must be accompanied by a concern for the protection of life, health, and property. These interests are superior to any competing interests held by any licensee.

[5] Federal Guidelines for Dam Safety, Federal Coordinating Council for Science, Engineering & Technology, June 25, 1979.

[6] Executive Office of the President, Office of Science and Technology Policy, December 6, 1978, at 8.

[7] *Federal Guidelines for Dam Safety*, Federal Coordinating Council for Science, Engineering & Technology, June 25, 1979, at 7.

Therefore, the Commission under section 10(c) of the Act, to help ensure effective and timely discharge of the licensee's responsibility, proposes these regulations.

Summary of the Proposed Regulation

Subpart A—General Provisions

The proposed rule revokes the existing dam inspection procedures in Part 12 of the Commission's regulations and replaces them with new practices and procedures that encompass dam inspections by independent consultants and other aspects of the Commission's dam safety program not previously included in Part 12.

Subpart A provides that this part applies to water power projects licensed under Part I of the Federal Power Act (Act). The proposed rule would not absolve any licensee from compliance with any term or condition of its license. The Commission or its designated representative may require that the licensee comply with the stricter of two similar provisions located in a license and this part.

The new Part 12 rules would also apply to an applicant for a license for a constructed project. Section 12.3 defines "applicant" as the owner or operator of an unlicensed constructed project who must, in the Commission's judgment, apply for a license, as well as those persons who have actually submitted a license application.

Section 12.3 also defines "authorized Commission representative" as the Directors of the Office of Electric Power Regulation and the Division of Hydropower Licensing, acting directors of these offices, any regional engineer, or any other specifically designated persons.

The definition of a "condition affecting the safety and adequacy of a project or project works" is important for the monitoring and reporting requirements of the rule. This phrase means any condition that may adversely affect the safety, stability, or integrity of any project works or the ability of any project works to protect life, health, or property, or the power and nonpower uses of the affected water resources. The definition provides several examples of conditions that might affect the safety and adequacy of a water power project or the project works.

Other terms defined in § 12.3 include "constructed project," "dam," "project emergency," "regional engineer" and "development." Furthermore, any terms defined in section 3 of the Federal Power Act have the same meaning as they have under the Act for purposes of this part, unless further defined in this part.

Section 12.4 sets forth with specificity the authority of the regional engineer or other authorized Commission representative to inspect and supervise the construction, operation, maintenance, use, or modification of any project works. The regional engineer or other Commission representative is authorized to test or inspect any project works or to require the licensee to do so; to require a licensee to submit certain reports or information; to require a licensee to modify emergency action plans or any plan for corrective measures; to take any preventative or corrective measures; and to prescribe a time for performing these actions. However, an order or directive of the regional engineer may be delayed or stayed under § 12.4(c) by the regional engineer or other authorized Commission representative or by the Commission itself.

Section 12.5 sets forth the general standard that a licensee or applicant must use sound and prudent engineering practices in designing, constructing, operating, maintaining, using, or modifying a water power project or the project works. As noted above, it is primarily the licensee's responsibility to protect life, health and property.

Subpart B—Reports and Records

Section 12.10 requires an applicant or licensee to report to the Commission orally and in writing any condition affecting the safety or adequacy of the water power project or the project works. It specifies the information that the regional engineer may require. The applicant or licensee is also required to

report any deaths or serious injuries that occur at, or are attributable to, the water power project.

Section 12.11 provides for reporting of project modifications to the regional engineer.

Section 12.12 specifies the kinds of records that must be maintained by the applicant or licensee and the appropriate locations at which to maintain permanent original project records and copies of such records. A provision is included to provide for the transfer of permanent project records to a successor licensee or the government, if ownership of the project changes.

Subpart C—Emergency Action Plans

This subpart constitutes a major element of the Commission's dam safety procedures. It requires an applicant or licensee to make provision for measures to be taken during a project emergency, including failure of the dam. Emergency action plans must be developed by an applicant or licensee in coordination with Federal, state, and local agencies. The plans must be filed with the regional engineer. The Commission will provide guidelines for preparing such plans.

This requirement will apply to all projects licensed under Part I of the Act unless exempted by the Commission under § 12.21. An exemption from the requirement of this subpart is not perpetual, and the applicant or licensee is charged with the responsibility of reviewing conditions upstream and downstream from the project to ascertain whether an emergency action plan would be advisable. An exemption may be revoked by the Commission if conditions change significantly.

Section 12.22 prescribes the contents of an emergency action plan. This section requires that the plan include measures for training project staff and for controlling flows of water in unusual circumstances. The plan must take into account time of day, in particular the occurrence of a project emergency during hours of darkness.

Section 12.22(c), requires the applicant or licensee of any project works that are located within ten miles of a nuclear power plant to file a radiological response plan. The plan must provide for emergency procedures in the event of an accident or incident at the nuclear power plant that results in the release of radioactivity into the air or water. The objective of the plan is to provide for the possibility of short-term abandonment of the project works, and continued generation of electric power and effective control of stream flows. A project which is exempted from the requirement to file an emergency action plan must still file a radiological response plan if there is a licensed nuclear power plant within ten miles. Normally, radiological response plans will be filed as supplements to emergency action plans.

Section 12.23 prescribes the deadlines for filing the emergency action plans.

Under § 12.24 emergency action plans must be comprehensively reviewed by the applicant or licensee at least once a year and updated to ensure adequate protection for life, health, or property affected by the project.

Under § 12.25 a licensee or applicant is required to post the most current emergency action plan. The posting must be in a prominent location so that it may be available to operating personnel. The licensee or applicant is also required to test the readiness of personnel for an emergency situation.

Subpart D—Inspection by Independent Consultants

This subpart is a revision of the Part 12 requirements in the existing regulations. While it continues to prescribe initial inspections and subsequent five-year inspections by independent consultants, it will require inspection of a larger number of project developments. Formerly, inspections by consultants were performed only on those dams more than thirty-five feet in height or impounding more than 2,000 acre-feet of water. The revised inspection requirements add to this category of dams any dam with a high hazard potential that the regional engineer determines requires an inspection. This recognizes that the need

for stringent measures to protect life, health, or property may depend on the location and other characteristics of a project development relative to certain geographic, demographic, and economic features of the vicinity. In addition, the height and impoundment criteria have been revised for adaptation to the mertric system.

Section 12.30 supplies additional definitions for this subpart. "Independent consultant" means a person that is not, and has not been within two years of being retained to perform an inspection under this subpart, an employee, agent, contractor, or consultant of the licensee or its affiliates. An independent consultant cannot have had substantial responsibility for the design, construction, or maintenance of the project under inspection during the previous 10 years. It is not intended to prohibit a person who performs an independent inspection from performing subsequent inspections under this rule.

"Height above streambed" and "gross storage capacity" are also defined in this section for purposes of this subpart.

Section 12.31 provides the general requirement that the project works of each development within the scope of this subpart must be inspected by a qualified independent consultant in order to identify any actual or potential deficiencies in the project works. Section 12.32 provides for exemption from the requirements of this subpart.

Section 12.33 prescribes the scope of the periodic inspections by an independent consultant. The inspection must include the review of all relevant reports, a physical field inspection, and an evaluation of certain project features.

Section 12.34 requires that, if the independent consultant discovers any condition that may necessitate emergency corrective measures, the consultant must notify the licensee. The licensee must report the need for the measure to the regional engineer.

Section 12.35 explains what information should be included in the report that an independent consultant must prepare and file pursuant to an inspection under this subpart. This section permits incorporation by reference of materials found in other inspection reports. The section sets forth the kinds of data and information that must be provided, the general nature of the analyses to be performed, and an outline of the nature of the recommendations a consultant must make. If any consultant involved in the dam inspection dissents from the major recommendations of the report, such dissenting views must be included in the report. Furthermore, any changes in information required under this section occurring after it has been initially reported shall be included in subsequent reports.

Section 12.36 provides for the timing of the periodic inspection by an independent consultant. The project works of any development must undergo inspections at five-year intervals dating from the initial inspection.

Section 12.36(b) specifies when a project development must be initially inspected. The timing of the initial inspection depends on the type of project. The first category of projects includes any development that has a dam that is more than 33 feet, or 10 meters in height above streambed, or that impounds a reservoir with a gross storage capacity of more than 2,000 acre feet, or 2.5 million cubic meters. The facility must be inspected not later than two years after the date of issuance of an order licensing the development, if it was constructed before the date of issuance of the order. For any development that was constructed after the date of issuance of the order licensing or amending a license to include the development, the initial inspection under this subpart must be completed and the report on it filed not later than five years from the date of the first commercial operation or the date on which the reservoir first reaches its normal maximum surface elevation, whichever occurs first.

For any other development, the initial inspection must be completed and the

report on it filed by a date specified by the regional engineer. The initial inspection must be made within two years following the date that the regional engineer notifies the licensee that an inspection and report is required.

Paragraph (b)(3) provide that any Part 13-inspection made before the effective date of this regulation may be considered an initial inspection. However, the first report filed under this rule for a development must contain the information and analysis required by § 12.35(b).

Section 12.37 explains what corrective measures the applicant or licensee must take under the supervision of the regional engineer.

Subpart E—Other Responsibilities of Applicant or Licensee

This subpart explains several responsibilities that every applicant or licensee has regarding the operation and maintenance of a project development. Section 12.40 requires that a quality control program be maintained during any construction, repair, or modification of the project works or while taking any corrective measures. Section 12.41 requires that an applicant or licensee make provisions for instruments to monitor the performance of the project works whenever conditions are found during design, construction, or operation of the project that might affect the safety or adequacy of the project or the project works.

Under § 12.42 warning and safety devices must be installed as necessary or desirable to protect the public. Under § 12.43 the Commission requires a licensee to keep power and communication lines and gas pipelines from obstructing navigation or otherwise endangering the public. Section 12.44 requires at least annual operation of spillway gates and load-testing of the standby emergency power for spillway gate operation at regular intervals. Finally, under § 12.45 an applicant or licensee must post notices at appropriate locations requesting any member of the public to report to the licensee any unusual ground or water condition that might adversely affect the project or its works.

Comment Procedure

Interested persons are invited to submit written views, comments, or suggestions in writing concerning all or part of the regulations proposed in this notice. An original and 14 copies of any comment should be filed with the Secretary of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments must be received by August 1, 1980, and should reference Docket No. RM80-31. Written submissions will be available for public inspection at the Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. The Commission will consider all written submittals which are timely filed before acting on the proposed regulations.

(Federal Power Act, as amended, 16 U.S.C. 792-828c; Department of Energy Organization Act, 42 U.S.C. 7101-7352; Executive Order No 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission proposes to revise Part 12, and to amend Part 3, Subchapter B, of Chapter 1, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

1. Part 12 is revised in the title and Table of Contents to read as follows:

PART 12—SAFETY OF WATER POWER PROJECTS AND PROJECT WORKS

Subpart A—General Provisions

Sec.

12.1 Applicability.
12.2 Rules of Construction.
12.3 Definitions.

Sec.

12.4 Staff administrative responsibility and supervisory authority.
12.5 Responsibilities of licensee or applicant.

Subpart B—Reports and Records

12.10 Reporting safety-related incidents.
12.11 Reporting modifications of project works.
12.12 Maintenance of records.

Subpart C—Emergency Action Plans

12.20 General requirements.
12.21 Exemptions.
12.22 Contents of emergency action plan.
12.23 Time for filing emergency action plan.
12.24 Review and updating of plans.
12.25 Posting and Readiness.

Subpart D—Inspection by Independent Consultant

12.30 Applicability and definition.
12.31 General requirement.
12.32 Exemption.
12.33 Specific inspection requirements.
12.34 Emergency corrective measures.
12.35 Report of the independent consultant.
12.36 Time for inspections and reports.
12.37 Taking corrective measures after the report.

Subpart E—Other Responsibilities of Applicant or Licensee

12.40 Quality control programs.
12.41 Monitoring instruments.
12.42 Warning and safety devices.
12.43 Power and communication lines and gas pipelines.
12.44 Testing spillway gates.
12.45 Instructions to the public.

Authority: Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352; Executive Order No. 12009, 3 CFR 142 (1978).

1. Part 12 is revised to read as follows:

Subpart A—General Provisions

§ 12.1 Applicability.

Except as otherwise provided in this part or ordered by the Commission or its authorized representative, the provisions of this part apply to:

(a) Any project licensed under Part I of the Federal Power Act; and

(b) Any unlicensed constructed project for which the Commission has determined that an application for license must be filed under Part I of the Act.

§ 12.2 Rules of Construction.

(a) If any term, condition, article, or other provision in a project license is similar to any provision of this part, the licensee must comply with the provision which is, in the judgment of the Commission or its authorized representative, the stricter or more stringent provision.

(b) A licensee may request from the Director of the Office of Electric Power Regulation a ruling on the applicability to its actions of any provision of this part that is similar to a provision of its license. A ruling by the Director may be appealed under § 1.7 of this chapter. Only those persons named in the request and who are named in a license may rely upon it.

§ 12.3 Definitions.

(a) *General rule.* Terms defined in section 3 of the Federal Power Act shall have the same meaning as they have under the Act, for purposes of this part, unless further defined in this part.

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Applicant" means any person who has applied for a license for an unlicensed, constructed project and any owner or operator of an unlicensed, constructed project for which the Commission has determined that an application for license must be filed.

(2) "Authorized Commission representative" means the Director of the Office of Electric Power Regulation, the Director of the Division of Hydropower Licensing, the regional engineer, any person specifically authorized by one of those officials to act in his or her stead, or any other member of the Commission staff whom the Commission may designate.

(3) "Condition affecting the safety or adequacy of a project or project works" means any condition, event, or action at the project which might compromise the safety, stability, or integrity of any project work with respect to its continuing ability to protect life, health, or property or to protect the water

resources of the region for navigation, water power development, or other beneficial public uses, including recreation, or otherwise adversely affect life, health, or property, including but not limited to:

(i) Unscheduled rapid draw-down of impounded water;

(ii) Failure of any water control facility, such as a gate or a valve;

(iii) Failure or unusual movement, subsidence, or settlement of any part of a project work;

(iv) Unusual concrete deterioration or cracking, including development of new cracks or the lengthening or widening of existing cracks;

(v) Piping, slides, or settlements of material in any dam, abutment, or embankment or areas adjacent to reservoirs;

(vi) Significant damage to slope protection;

(vii) Unusual instrumentation readings;

(viii) New seepage or leakage or significant gradual increase in pre-existing seepage or leakage;

(ix) Sinkholes;

(x) Significant instances of vandalism or sabotage;

(xi) Natural disasters, such as floods or earthquakes; or

(xii) Any other signs of instability of any project work.

(4) "Constructed project" means any project with an existing dam.

(5) "Dam" means any structure for impounding or diverting water.

(6) "Development" means that part of a project comprising an impoundment and its associated dams, forebays, water conveyance facilities, power plant, and other appurtenant facilities. A project may comprise of one or more developments.

(7) "Project emergency" means an impending or actual sudden release of water at the project caused by natural disaster, accident, or failure of project works.

(8) "Regional engineer" means the person in charge of the Commission's regional office for the region (Atlanta, Chicago, Fort Worth, New York, or San Francisco) where a particular project is located or any staff member specifically designated by that person to act in his or her stead.

(9) "Act" means the Federal Power Act.

§ 12.4 Staff administrative responsibility and supervisory authority.

(a) *Administrative responsibility.* The Director, Office of Electric Power Regulation, is responsible for administering the Commission's dam safety program and reports directly to the Chairman of the Federal Energy Regulatory Commission.

(b) *Supervisory authority of the regional engineer or other authorized representative.* (1) Any water power project and the construction, operation, maintenance, use, or modification of any project works are subject to the inspection and the supervision of the regional engineer or any other authorized Commission representative.

(2) A regional engineer or other authorized Commission representative may:

(i) Test or inspect any water power project or project works or require that the applicant or licensee perform such tests or inspections or install monitoring instruments.

(ii) Require an applicant or a licensee to submit reports or information, regarding:

(A) The design, construction, operation, maintenance, use, repair, or modification of a water power project or project works;

(B) Any condition affecting the safety or adequacy of a project or project works or any death or injury that occurs at, or might be attributable to, the water power project;

(iii) Require an applicant or a licensee to modify:

(A) Any emergency action plan filed under Subpart B of this part;

(B) Any plan of corrective measures, including related schedules, submitted after the report of an independent consultant pursuant to § 12.36, or any other inspection report;

(iv) Require an applicant or licensee to take any other action with respect to the design, construction, operation, maintenance, repair, use, or modification of the project or its works that is, in the judgment of the regional engineer or other authorized representative, necessary or desirable to maintain the safety and adequacy of the project or its works for the protection of life, health, or property or for the protection of the water resources of the region for navigation, water power development, or other beneficial public uses;

(v) Establish the time for an applicant or licensee to perform any actions specified in this paragraph.

(c) *Stay of order or directive.*

(1) Any order or directive issued under this section by a regional engineer or other authorized Commission representative is immediately effective and remains in effect until:

(i) The regional engineer or other authorized representative who issued the order or directive stays its effect for a particular period;

(ii) The Commission stays the effect of the order or directive, or modifies or reverses the order or directive on appeal.

(2) A motion for stay of any order or directive issued under this section must contain a full explanation of why a stay of the order or directive for the period requested will not endanger life, health, or property.

§ 12.5 Responsibilities of licensee or applicant.

A licensee or applicant must use sound and prudent engineering practices in any action relating to the design, construction, operation, maintenance, use, repair, or modification of a water power project or project works.

Subpart B—Reports and Records

§ 12.10 Reporting safety-related incidents.

(a) *Conditions affecting the safety or adequacy of a project or its works.*—(1) *Oral reports.* An applicant or licensee must report by telephone to the regional engineer any condition affecting the safety or adequacy of a project or projects works, as defined in § 12.3(b)(3). The oral report must be made as soon as practicable after that condition is discovered, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency action procedure.

(2) *Written reports.* Following the oral report required in paragraph (a)(1) of this section, the applicant or licensee must submit to the regional engineer a written report on the condition affecting the safety or adequacy of the project or project works, subcribed and verified in accordance with § 1.16 of this chapter. The written report must be submitted within the time specified by the regional engineer and must contain any information the regional engineer directs, including:

(i) The causes of the condition;

(ii) Description of any unusual occurrences or operating circumstances preceding the condition;

(iii) An account of any measure taken to prevent worsening of the condition;

(iv) A detailed description of any damage to project works and the status of any repair;

(v) A detailed description of any personal injuries;

(vi) A detailed description of the nature and extent of any private property damage; and

(vii) Any other information the regional engineer considers relevant.

(3) The level of detail required in any written report must be commensurate with the severity and complexity of the condition.

(b) *Deaths or serious injuries.* The applicant or licensee must promptly report to the regional engineer in writing, subscribed and verified in accordance with § 1.16 of this chapter, any drowning or other accident resulting in death or serious injury that occurs at the project, including a description of the cause and location of the accident. The written report of any death or serious injury considered or alleged to be project-related must also describe any remedial actions taken or proposed to avoid or reduce the chance of similar

occurrences in the future. For the purpose of this paragraph, "project-related" includes any deaths or serious injuries involving a dam, spillway, or intake or which take place at or immediately above or below a dam.

§ 12.11 Reporting modifications of project works.

(a) *Reporting requirements.* Regardless of whether a particular modification is permitted without specific prior Commission approval, an applicant or licensee must report any modification of project works to the regional engineer in writing, subscribed and verified in accordance with § 1.16 of this chapter, at the time specified in paragraph (b) of this section.

(b) *Time of reporting.* (1) Any modification that is an emergency measure taken in response to a condition affecting the safety or adequacy of the project or project works must be submitted with the report of that condition required by § 12.10(a)(2);

(2) In all other instances, the modification must be reported at least 15 days before work on the modification begins.

§ 12.12 Maintenance of records.

(a) *Kinds of records.* The applicant or licensee must maintain the following information as permanent project records:

(1) *Engineering data.* Engineering data relating to design, construction, maintenance, repair, or modification of the project, including design memoranda and drawings, laboratory and other testing reports, foundation treatment and excavation, plans and specifications, inspection and quality control reports, "as built" construction drawings, designers' operating criteria, and any other data necessary to demonstrate that construction, maintenance, repair, or modification of the project has been performed in accordance with plans and specifications;

(2) *Instrumentation.* Instrumentation observations and data collected during construction, operation, or maintenance of the project, including continuously maintained tabular records and graphs illustrating the data collected pursuant to § 12.41;

(3) *Operational and maintenance history* of the project, including:

(i) The dates, times, nature, and causes of any complete or partial unscheduled shut-down, suspension of project operations, or reservoir filling restrictions related to the safety or adequacy of project works;

(ii) Any reports of project modifications, conditions affecting the safety or adequacy of the project or its works, or deaths or serious injuries at the project.

(b) *Location of records.* (1) *Original records.* The applicant or licensee must maintain the originals of all permanent project records at a central location secure from damage from any conceivable failure of the project works and convenient for inspection, such as the main business office of the applicant or licensee. The applicant or licensee must keep the regional engineer advised of the location of the permanent project records.

(2) *Record copies.* If the originals of the permanent project records are maintained at a central location other than the project site, the applicant or licensee must maintain copies of all permanent project records at the project site.

(c) *Transfer of records.* If the project is taken over by the Federal government at the end of a license term or the Commission issues a new license to a different licensee, the prior licensee must transfer the originals of all permanent project records to the custody of the administering Federal agency or department or to the new licensee.

Subpart C—Emergency Action Plans

§ 12.20 General requirements.

(a) Unless provided with a written exemption pursuant to § 12.21, every applicant or licensee must develop and file with the regional engineer three copies of an emergency action plan subscribed and verified in accordance with § 1.16 of this chapter.

(b) The emergency action plan must be:

(1) Developed after consultation and cooperation with appropriate Federal, state, and local agencies responsible for public health and safety; and

(2) Designed to provide early warning to upstream and downstream inhabitants, property owners, operators of water-related facilities, recreational users, and other persons in the vicinity who might be affected by a project emergency, as defined in § 12.3(b)(7).

§ 12.21 Exemptions.

(a) *Grant of exemption.* If an applicant or licensee satisfactorily demonstrates that no project emergency would endanger life, health, or property, the Director of the Office of Electric Power Regulation or the regional engineer may exempt the applicant or licensee from filing an emergency action plan.

(b) *No exemption.* A licensee or applicant for a license for a project with a dam or powerhouse located within ten miles of a nuclear power plant may not be exempted from the requirements of § 12.22(c) for a radiological response plan.

(c) *Conditions of exemptions.* (1)(i) An applicant or licensee who receives an exemption from filing an emergency action plan has continuing responsibility to review circumstances upstream and downstream from the project to determine if, as a result of change circumstances, a project emergency might endanger life, health, or property.

(ii) Comprehensive review of the need for an emergency action plan must be conducted at least once each year.

(2) Promptly after the applicant or licensee learns that, as a result of any change in circumstances, a project emergency might endanger life, health, or property, the applicant or licensee must inform the regional engineer of that changed condition.

(d) *Revocation.* (1) The Director of the Office of Electric Power Regulation or the regional engineer may revoke an exemption granted under this section if he or she determines that, as a result of any change in circumstances, a project emergency might endanger life, health, or property.

(2) If an exemption is revoked, the applicant or licensee must file an emergency action plan within the time specified by the Director of the Office of Electric Power Regulation or the regonal engineer in revoking the exemption.

§ 12.22 Contents of emergency action plan.

(a) *General requirement.* An emergency action plan must conform with the guidelines established by the Director of the Office of Electric Power Regulation (available from the Division of Hydropower Licensing or the regional engineer) and must include:

(1) Plans for training project operators, attendants, and other responsible personnel to respond properly during a project emergency, including the instructions on the procedures to be followed thoughout a project emergency and the manner in which the licensee will periodically review the knowledge and understanding that these personnel have of those procedures;

(2) Detailed plans for notifying potentially affected persons, appropriate Federal, state, and local agencies, including public safety and law enforcement bodies, and medical units;

(3) Procedures for controlling the flow of water, including actions to reduce inflows to reservoirs, such as limiting outflows from upstream dams or control structures, and actions to reduce downstream flows, such as limiting outflows from downstream dams or control structures, on the waterway on which the project is located or its tributaries;

(4) A summary of the study used for determining the upstream and downstream areas that may be affected by sudden release of water, including a summary of all criteria and assumptions used in the study and, if required by the regional engineer, inundation maps.

(b) *Special factors.* The applicant or licensee must take into account in its emergency action plan the time of day, particularly hours of darkness, in establishing the proper actions and

procedures for use during a project emergency.

(c) *Additional requirements for projects near nuclear power plants.*—(1) *Radiological response plan.* A licensee or an applicant for a project with a dam or powerhouse located within ten miles of a nuclear power plant must file, separately or as a supplement to any emergency action plan, a radiological response plan which provides for emergency procedures to be taken if an accident or other incident results in the release of radioactive materials from the nuclear power plant.

(2) A radiological response plan must include sufficient procedural safeguards to ensure that, to the maximum extent possible, during the accident or other incident at the nearby nuclear power plant:

(i) the project may be safely operated and, if evacuation is necessary, the project may be left unattended without danger to the project equipment or works or to life, health, or safety upstream or downstream from the project; and

(ii) electric power may be generated at and transmitted from the project without interruption.

(3) *Time of filing.*—

(i) *Constructed project with an acceptable emergency action plan.* For a constructed project with an otherwise acceptable emergency action plan on file, any radiological response plan required must be filed:

(A) If an operating license for the nuclear power plant has been issued on or before [the effective date of these regulations], not later than three months from [the effective date of these regulations];

(B) In all other instances, not later than three months after the date an operating license for the nuclear power plant is issued.

(ii) *All other projects.* For any project not described in § 12.22(3)(i), any radiological response plan required must be filed contemporaneously with the emergency action plan or, if the project has been exempted from filing an emergency action plan, at the time the emergency action plan would otherwise have been required to be filed pursuant to § 12.23.

§ 12.23 Time for filing emergency action plan.

(a) *Unconstructed project.* The emergency action plan for any unconstructed project must be filed no later than 30 days before the initial filling of the project reservoir begins.

(b) *Unlicensed constructed project.* (1) If the Commission has determined on or before [the effective date of these regulations] that a license is required for an unlicensed constructed project, the emergency action plan for that project must be filed not later than:

(i) Six months after [the effective date of these regulations]; or

(ii) Any earlier date specified by the Commission or its authorized representative.

(2) Except as set forth in paragraph (b)(1) of this section, the emergency action plan for an unlicensed constructed project must be filed not later than the earliest of:

(i) Six months after the date that a license application is filed;

(ii) Six months after the date that the Commission issues an order determining that licensing is required; or

(iii) A date specified by the Commission or its authorized representative.

(c) *Licensed constructed project.* If a licensed constructed project does not have an acceptable emergency action plan on file on [the effective date of these regulations] the emergency action plan must be filed no later than:

(1) Six months after [the effective date of these regulations]; or

(2) Any earlier date specified by the Commission or its authorized representative.

§ 12.24 Review and updating of plans.

(a)(1) An applicant or licensee has continuing responsibility to review the adequacy of the emergency action plan in light of any changes in upstream or downstream circumstances which might affect water flows or the location or

extent of the areas, persons, or property that might be harmed in a project emergency.

(2) Promptly after an applicant or licensee learns of any change in circumstances described in paragraph (a)(1) of this section, the applicant or licensee must:

(i) Inform the regional engineer of that change in circumstances;

(ii) Consult and cooperate with appropriate Federal, state, and local agencies responsible for public health and safety to determine any advisable revisions to the emergency action plan; and

(iii) File with the regional engineer three copies of any revisions to the studies, maps, plans, procedures, or other information contained in the emergency action plan which result from that consultation.

(b) An applicant or licensee must conduct a comprehensive review of the adequacy of the emergency action plan at least once each year.

§ 12.25 Posting and readiness.

(a) A copy of the most recent emergency action plan must be posted in a prominent location readily accessible to the licensee's or applicant's operating personnel.

(b) Each licensee or applicant must annually test the state of training and readiness of key personnel responsible for responding properly during a project emergency, to ensure that they know and understand the procedures to be followed throughout a project emergency.

Subpart D—Inspection by Independent Consultants

§ 12.30 Applicability and definitions.

(a) This subpart applies to any licensed project development that has a dam:

(1) That is more than 33 feet (10 meters) in height above streambed, as defined in paragraph (b)(3) of this section;

(2) That impounds a reservoir with a gross storage capacity of more than 2,000 acre-feet (2.5 million cubic meters); or

(3) That has a high hazard potential, as defined in paragraph (b)(2) of this section, and is determined by the regional engineer or other authorized Commission representative to require a Part 12 inspection.

(b) *Definitions.* For purposes of this subpart:

(1) "Independent consultant" means any person that:

(i) Is not, and has not been within two years before being retained to perform an inspection under this subpart, an employee, agent, contractor, or consultant of the licensee or its affiliates; and

(ii) Has not had substantial responsibility for the design, construction, or maintenance of the project under inspection for 10 years, except as an independent consultant.

(iii) This paragraph is not intended to prohibit a person from performing an inspection under this subpart solely on the ground that the person performed a prior inspection under this subpart or the provisions of Part 12 of this chapter.

(2) "Dam that has high hazard potential" means any dam whose failure, in the judgment of the Commission or its authorized representative, might present a significant risk of endangering human life or of causing significant property damage or which meets the criteria for high hazard potential as defined by the Corps of Engineers (33 CFR Part 222, Table 2).

(3) "Height above streambed" means:

(i) For a dam with a spillway, the vertical distance from the lowest elevation of the natural streambed at the downstream toe of the dam to the maximum water storage elevation possible without any discharge from the spillway. The maximum water storage elevation is:

(A) For gated spillways, the elevation of the tops of the gates;

(B) For ungated spillways, the elevation of the spillway crest or the top of any flashboards.

(ii) For a dam without a spillway, the vertical distance from the lowest elevation of the natural streambed at the downstream toe of the dam to the lowest point on the crest of the dam.

(4) "Gross storage capacity" means the maximum possible volume of water impounded by a dam with zero spill, that is, without the discharge of water over the dam or a spillway.

§ 12.31 General requirement.

In accordance with the procedures in § 12.33, the project works of each development to which this subpart applies, excluding transmission and transformation facilities and generating equipment, must be periodically inspected by or under the responsibility and direction of at least one independent consultant experienced in the design, construction, operation, and maintenance of dams, in order to identify any actual or potential deficiencies, whether in the condition of those project works or in the quality or adequacy of project maintenance, surveillance, or methods of operation, that might endanger public safety.

§ 12.32 Exemption.

Upon written request from the licensee, the Director of the Office of Electric Power Regulation may grant an exemption from the requirements of this subpart in extraordinary circumstances that clearly establish good cause for exemption. The Director may prescribe suitable conditions for an exemption.

§ 12.33 Specific inspection requirements.

(a) *Scope of inspection.* The inspection by the independent consultant must:

(1) Duly consider all relevant reports on the safety of the development made by or written under the direction of Federal or state agencies, submitted under Commission regulations, or made by other consultants;

(2) Include physical field inspection of the project works and review and assessment of all relevant data concerning:

(i) Settlement;
(ii) Movement;
(iii) Erosion;
(iv) Seepage;
(v) Leakage;
(vi) Cracking;
(vii) Deterioration;
(viii) Seismicity;
(ix) Internal stress and hydrostatic pressures in project structures or their foundations or abutments;
(x) Functioning of foundation drains and relief wells;
(xi) The stability of critical slopes adjacent to a reservoir or project works; and
(xii) Regional and site geological conditions.

(3) Include specific evaluation of:
(i) The adequacy of spillways;
(ii) The effects of overtopping of nonoverflow structures;
(iii) The structural adequacy and stability of structures under all credible loading conditions;
(iv) The relevant hydrological data accumulated since the project was constructed or last inspected under this subpart;
(v) The history of the performance of the project works through analysis of data from monitoring instruments, and
(vi) The quality and adequacy of maintenance, surveillance, and methods of project operations for the protection of public safety.

(b) *Evaluation of spillway adequacy.* The adequacy of any spillway must be evaluated by considering the upstream and downstream hazard potential which would result from failure of the project works during flood flows.

(1) If structural failure would present a hazard to human life or cause significant property damage, the independent consultant must evaluate the ability of project works to withstand the loading or overtopping which may occur in a flood up to the probable maximum flood or the capacity of spillways to prevent the reservoir from rising to an elevation that would endanger the project works.

(2) If structural failure would not present a hazard to human life or cause significant property damage, spillway adequacy may be evaluated by means of a design flood of lesser magnitude than the probable maximum flood, if the report of the independent consultant pursuant to § 12.35 provides a detailed explanation of the bases for the finding that structural failure would not present a hazard to human life or cause significant property damage.

(c) During the inspection under this section, the independent consultant must use any special equipment and instrumentation and any specialized technical personnel that may prudently be necessary.

§ 12.34 Emergency corrective measures.

If, in the course of an inspection, an independent consultant discovers any condition for which emergency corrective measures are advisable, the independent consultant must immediately notify the licensee and the licensee must report that condition to the regional engineer pursuant to § 12.10(a).

§ 12.35 Report of the independent consultant.

(a) *General requirement.* Following inspection of a project development as required under this subpart, the independent consultant must prepare a report and the licensee must file three copies of the report with the regional engineer. The report must conform to the provisions of this section and be satisfactory to the authorized Commission representative.

(b) *General information in the initial report.* (1) The initial report filed under this subpart for any project development must contain:

(i) A description of the project development;

(ii) A map of the region indicating the location of the project development;

(iii) Plans, elevations, profiles, and sections of the principal project works; and

(iv) A summary of the design assumptions, design analyses, spillway design flood, and the factors of safety used to evaluate the stability of the project works.

(2) To the extent that the information and analysis required in paragraph (b)(1) of this section are contained in a report of an independent consultant prepared and filed in compliance with Commission regulations in effect before [the effective date of these regulations], that information and analysis may be incorporated by specific reference into the first report prepared and filed under this subpart.

(c) *Information required for all reports.* Any report of an independent consultant filed under this subpart must contain the information specified in this paragraph.

(1) *Monitoring information.* (i) The report must contain monitoring information that includes time-versus-reading graphs depicting data from critical and repesentative monitoring instruments that measure the behavior, movement, deflection, or loading of project works or from which the stability, performance, or functioning of the structures may be determined.

(ii) Any monitoring data plotted on graphs must be presented in a manner that will facilitate identification and analysis of trends. The data may be summarized to facilitate graphical representation.

(iii) Plan or sectional drawings of project structures sufficient to show the location of all critical and representative monitoring instruments must be included.

(2) *Analyses.* The report must:

(i) Analyze the safety and adequacy of the project works and the maintenance and methods of operation of the development fully in light of the independent consultant's reviews, field inspections, assessments, and evaluations described in § 12.33;

(ii) Identify any changes in the information and analysis required by paragraph (b) of this section that have occurred since the last report by an

independent consultant under this subpart and analyze the implications of those changes; and

(iii) Evaluate the adequacy of existing monitoring instruments, periodic observation programs, and other methods of monitoring project works and conditions affecting the safety or adequacy of the project or project works with respect to the development.

(3) *Recommendations.* Based on the independent consultant's field observations and analyses of the project works and the maintenance, surveillance, and methods of operation of the development, the report must contain the independent consultant's recommendations on:

(i) Any corrective measures necessary for the structures or for the maintenance or surveillance procedures or methods of operation of the project works;

(ii) A reasonable time to carry out each corrective measure; and

(iii) Any new or additional monitoring instruments, periodic observations, or other methods of monitoring project works or conditions that may be required.

(4) If the inspection and report were conducted and prepared by more than one independent consultant, the report must clearly indicate any dissenting views about the analyses of recommendations of the report that might be held by any individual consultant.

(5) *List of participants.* The report must identify all persons who participated in the inspection of the project or in preparation of the report and the persons who directed those activites.

(6) *Statement of independence.* The independent consultant must declare that all conclusions and recommendations in the report are made independently of the licensee, its employees, and its representatives.

(7) *Signature and verification.* The report must be signed by each independent consultant responsible for the report. The report must be verified in accordance with § 1.16 of this chapter.

§ 12.38 Time for inspections and reports.

(a) *General Rule.* After the initial inspection and report under this subpart for a project development, a new inspection under this subpart must be completed and the report on it filed not later than five years from the date the last report on an inspection was filed under this subpart.

(b) *Initial Inspection and Report.*

(1) For any development that has a dam which is more than 33 feet (or 10 meters) in height above streambed, or which impounds a reservoir with gross storage capacity of more than 2,000 acre-feet (or 2.5 million cubic meters), which development was constructed before the date of issuance of the order licensing or amending a license to include the development, the initial inspection under this subpart must be completed and the report on it filed not later than two years after the date of issuance of the order licensing it or amending a license to include it.

(2) For any development that was constructed after the date of issuance of the order licensing or amending a license to include the development, the initial inspection under this subpart must be completed and the report on it filed not later than five years from the date of first commercial operation or the date on which the reservoir first reaches its normal maximum surface elevation, whichever occurs first

(3) For any development not set forth in paragraph (b)(1) or (2) of this section, the initial inspection under this subpart must be completed and the report on it filed by a date specified by the regional engineer, not to exceed two years after the date that the regional engineer notifies the licensee that an inspection and report under this subpart are required.

(4) The last independent consultant's inspection and report made for a development before [the effective date of these regulations] in compliance with the Commission regulations then in effect is deemed to fulfill the requirements for an initial inspection and report under this subpart for that development must contain the

information and analysis required by § 12.35(b).

§ 12.37 Taking corrective measures after the report.

(a) *Corrective plan and schedule.* (1) Not later than 30 days after the report of the independent consultant is filed with the regional engineer, the licensee must submit to the regional engineer a plan and schedule for designing and carrying out any corrective measures that the licensee proposes.

(2) The plan and schedule may include any proposal, including taking no action, that the licensee considers a preferable alternative to any corrective measure recommended in the report of the independent consultant. Any proposed alternative must be accompanied by the licensee's complete justification and detailed analysis and evaluation in support of that alternative

(b) *Carrying out the plan.* The licensee must complete all corrective measures in accordance with the plan and schedule submitted to, and approved or modified by, the regional engineer.

(c) *Extension of time period.* For good cause shown, the regional engineer may permit additional time to submit the plan and schedule required by this section.

Subpart E—Other Responsibilities of Applicant or Licensee

§ 12.40 Quality control programs.

During any construction, repair, or modification of project works, including any corrective measures taken pursuant to § 12.37, the applicant or licensee must maintain a quality control program that is commensurate with the scope of the work and meets any requirements or standards set by the regional engineer. Quality control inspection must be done by the licensee, the design engineer, or an independent firm directly accountable to the licensee. Quality control inspection must not be done by the construction contractor or a firm accountable to the construction contractor.

§ 12.41 Monitoring instruments.

(a) In designing a project, a licensee must make adequate provision for installing and maintaining appropriate monitoring instrumentation whenever any physical condition that might affect the stability of a project structure has been discovered or is anticipated. The instrumentation must be satisfactory to the regional engineer and may include, for example, instruments to monitor movement of joints, foundation or embankment deformation, seismic effects, hydrostatic pore pressures, structural cracking, or internal stresses on the structure.

(b) If an applicant or licensee discovers any condition affecting the safety or adequacy of the project or project works during the course of construction or operation, the applicant or licensee must install and maintain any instruments that may be required by the regional engineer of other authorized Commission representative to monitor that condition.

§ 12.42 Warning and safety devices.

To the satisfaction of, and within a time specified by, the Regional engineer, an applicant of licensee must install, operate, and maintain any signs, lights, sirens, barriers, or other safety devices that may reasonably be necessary or desirable to warn the public of fluctuations in flow from the project or otherwise to protect the public in its use of project lands and waters.

§ 12.43 Power and communication lines and gas pipelines.

(a) A licensee must take all reasonable precautions, and comply with any specifications that may be provided by the regional engineer, to ensure that any power or communication line or gas pipeline that is located over under or in project waters does not obstruct navigation for recreational or commercial purposes or otherwise endanger public safety.

(b) Clearances between power and communication lines and any vessels using project waters must be at least sufficient to conform to any applicable

requirements of the National Electrical Safety Code.

§ 12.44 Testing spillway gates.

(a) *General requirement.* An applicant or licensee must make adequate provision, to the satisfaction of the authorized Commission representative, to ensure that all spillway gates are operable during adverse weather conditions.

(b) *Annual test.* (1) At least once each year, each spillway gate at a project must be operated to spill water, either during regular project operation or on a test basis.

(2) If an applicant or licensee does not operate each spillway gate on a test basis during the periodic inspection by the Commission Staff, the applicant or licensee must submit to the regional engineer at the time of that inspection a written statement, subscribed and verified pursuant to § 1.16 of this chapter, that each spillway gate has been operated at least once during the preceding twelve months.

(c) Load-test of standby power. (1) The applicant or licensee must load-test the standby emergency power for spillway gate operation at regular intervals during each year and submit to the regional engineer at the time of the periodic inspection by the Commission staff a written statement, subscribed and verified pursuant to § 1.16 of this chapter, describing the intervals at which the standby emergency power was load-tested during the preceding year.

(2) The Commission staff may direct that a spillway gate be operated using standby emergency power during the periodic inspection.

§ 12.45 Instructions to the public.

(a) An applicant or licensee must post conspicuously and maintain the sign described in paragraph (b) of this section at all major points of public access in the vicinity of the project dams or dikes, in order to obtain the assistance of the public in the protection of life, health, and safety.

(b) Instructions to the public must be printed in 50 point type on any durable material suitable for outdoor posted notices and read:

PUBLIC NOTICE

If you see any unusual condition or disturbance in the vicinity of dams or dikes, such as an earth slide, excessive erosion, water seepage, or discoloration of water, please report it as soon as possible to the owner or operator of this power project by calling the number listed below.

Name: _____

Phone: _____

PART 3—ORGANIZATION; OPERATION; INFORMATION AND REQUESTS

2. Part 3 is amended in § 3.111 to read as follows:

§ 3.111 Investigations.

(a) *Water Power Resources.* Under section 4(a) of the Act, the Commission may investigate water resources development, the water power industry, power sites, and the use of power from government dams. These investigations may be initiated by the Commission on its own motion, request of another federal or state agency, or complaint. The staff work is performed by the Office of Electric Power Regulation and the Office of the General Counsel. These investigations may be conducted in cooperation with other government agencies.

(b) *Electric Power Development.* Under section 4(g) of the Act, the Commission may investigate any occupancy or evidenced intention to occupy, for the purpose of developing electric power, public lands, reservations, or streams or other bodies of water over which Congress has jurisdiction under its authority to regulate commerce with foreign nations and among the states. These investigations may be initiated by the Commission on its own motion, request of another federal or state agency, or complaint. The staff work is performed by the Office of Electric Power Regulation and the Office of General Counsel. After such an investigation, the Commission may issue any order found appropriate, expedient, and in the public interest to conserve and utilize the

navigation and water power resources of the region, including an order requiring licensing. If an investigation shows that the Act requires that a project be licensed, the Secretary may inform the owner of the project.

3. Part 3 is further amended in the Table of Contents and in the text of the regulations by amending § 3.119 to read as follows:

§ 3.119 Field inspections.

(a) The Office of Electric Power Regulation, principally through the Commission's regional offices, or through designated federal agencies, conducts periodic field inspections to monitor:

(1) Compliance with the terms of preliminary permits;

(2) The continuing safety and adequacy of licensed and unlicensed projects for the protection of life, health, and property and for the protection of the water resources of the region for navigation, water power development, and other beneficial public uses, including recreational purposes; and

(3) Compliance with the terms of orders and licenses and with approved plans, drawings, and specifications in the construction, operation, and maintenance of projects.

(b) The Commission or any of its authorized representatives may direct or conduct additional inspections at any project at any time.

¶ 32,072 Annual Report for Natural Gas Companies (Class A and Class B): Revision of Form No. 2

45 F. R. 46075 (July 9, 1980).

18 CFR Part 260

[Docket No. RM80-56]

Annual Report for Natural Gas Companies (Class A and Class B): Revision of Form No. 2

July 1, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission gives notice that it proposes to revise its annual report, Form No. 2, "Annual Report for Natural Gas Companies (Class A and B)" (18 CFR 260.1). The proposed amendments would eliminate certain data elements which the Commission no longer needs to carry out its regulatory functions. The proposed changes are a product of the Commission's ongoing effort to eliminate unnecessary reporting burdens.

DATE: Comments are due by August 29, 1980.

ADDRESS: Comments on this Notice should be addressed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM80-56.

FOR FURTHER INFORMATION CONTACT:

James Kitchen, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 3408N, Washington, D.C. 20426, (202) 357-9212.

Elaine M. Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 3405N, Washington, D.C. 20426, (202) 357-9190.

I. Background

The Federal Energy Regulatory Commission (Commission) is engaged in an ongoing effort to eliminate unnecessary reporting burdens. This rulemaking to amend Form No. 2, "Annual Report for Natural Gas Companies (Class A and Class B)," [1] is part of that effort, and reflects a new evaluation of the data needed by the Commission to carry out its regulatory functions. The proposed revisions for the form should result in a significant reduction in respondent's reporting burdens.*

Form No. 2 collects information annually from natural gas companies. The data primarily include general corporate information; summary financial data; balance sheet supporting data; income statement supporting data; and gas plant, sales, operating and statistical data.[2]

The Commission has reviewed Form No. 2 in light of its regulatory responsibilities and has determined that it no longer needs certain elements of the data collected. The proposed deletions would cause an estimated 19

[1] A Class A natural gas company is one having annual gas operating revenues of $2,500,000 or more. A Class B natural gas company is one having annual gas operating revenues of $1,000,000 or more but less than $2,500,000. These classification criteria have not been examined for this rulemaking; they will, however, be the subject of a separate rulemaking.

* FERC Form No. 2 (Attachment B) is not being printed by the **Federal Register**. Copies are available in the Office of Public Information.

[2] The Commission is authorized to prescribe the reporting requirements of Form No. 2 pursuant to sections 10(a) and 16 of the Natural Gas Act (15 U.S.C. 717-717w).

percent reduction in the current reporting burden for the form.[3]

The Energy Information Administration (EIA), however, may decide on behalf of itself or other sponsors within the Department of Energy to continue the collection of some data proposed for deletion herein. If EIA should make such a determination during this rulemaking proceeding, the Commission would issue a Final Rule based on this Notice with a delayed effective date. This would provide EIA (or any other potentially interested agency) a period of time in which to justify the need for the data and receive the approval for collection of such data under the agency's own authority.

II. Summary of Revisions

Sixty-two of the schedules in Form No. 2 will not be amended. The following is a brief summary of the Commission's proposed revisions to Form No. 2: [4]

a. Eliminate the requirement for CPA certification of 15 of the 19 schedules presently requiring such certification.

b. Establish specific threshold reporting levels on 13 schedules.

c. Revise the reporting instructions on 17 schedules.

d. Delete entire data columns from 10 schedules.

e. Delete 33 schedules in their entirety.

III. Comment Procedures

The Commission invites interested persons to submit written comments on this proposal. Copies of all comments will be furnished to EIA for its use. The Commission specifically requests that the comments address the following questions:

1. a. Do the proposed revisions or eliminations of data affect any Commission or State regulatory functions?

b. Will State agencies now utilizing this report form in the exercise of their own regulatory responsibilities agree to reduce their reporting requirements concurrently?

2. Is there any reason for continued collection of the data for the purposes of another Federal agency? Suggestions for the continued collection of data which have been proposed for elimination from the present Form No. 2 should identify the proper agency and the basis and purpose for its collection of the data.

3. What cost savings are likely to result from the proposed elimination of the 15 CPA certifications? [5]

4. What are the merits of using a percentage of the year end account balance rather than a selected fixed dollar figure in establishing a threshold for "minor items"?

5. What is the effect of deleting the INDEX from the back of the report form? [6]

Interested persons wishing to comment on this proposal should submit copies of their comments to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 and should refer to Docket No. RM80-56. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, August 29, 1980, will be considered by the Commission prior to promulgation of final regulations. Pursuant to the Federal Reports Act, 44 U.S.C. § 3501-3511, these proposed revisions will be considered by the Office of Management and Budget for clearance.

All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection during

[3] This is a conservative estimate, in that the information requirements in many of the schedules to be deleted are open-ended. As a result, some responses to these schedules can vary between zero and several hundred lines.

[4] *See* Attachment A for a chart of the proposed revision to Form No. 2. *See* Attachment B for Form No. 2, as revised.

[5] Responses to this question are especially requested from CPA firms.

[6] Form No. 2 contains a list of Schedules at pages iii through v, including the page locations of each schedule. Each of the financial statements (balance sheet and income statement) contains a column for the page number of the statement's supporting schedule.

regular business hours in the Commission's Division of Public Information, Room 1000, 825 N. Capitol Street NE., Washington, D.C. 20426.

(Natural Gas Act, as amended, 15 U.S.C. 717-717w; Department of Energy Organization Act, 42 U.S.C. 7101-7352; E. O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to revise Form No. 2, "Annual Report for Natural Gas Companies (Class A and Class B)," prescribed by § 260.1, Chapter I, Title 18 of the Code of Federal Regulations as set out in Attachment B.

In addition, in consideration of the foregoing, the Commission proposes to revise Part 260 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Part 260—Statements and Reports (Schedules) is amended in the Table of Contents and in the text of the regulations by revising § 260.1 to read as follows:

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

260.1 FERC Form No. 2, Annual Report for Natural Gas Companies (Class A and Class B).

* * * * *

§ 260.1 FERC Form No. 2, Annual Report for Natural Gas Companies (Class A and Class B).

(a) The form of Annual Report for Class A and Class B natural gas companies, designated herein as FERC Form No. 2, is prescribed for the year 1980 and thereafter.

(b) Each natural gas company, as defined in the Natural Gas Act (15 U.S.C. 717, et seq.) which is included in Class A or Class B as defined in the Commission's Uniform System of Accounts Prescribed for Natural Gas Companies subject to the provisions of the Natural Gas Act, shall prepare and file with the Commission for the year beginning January 1, 1980, or subsequently during the calendar year 1980, if its established fiscal year is other than the calendar year, and for each year thereafter, on or before the last day of the third month following the close of the calendar year or other established fiscal year, an original and such number of conformed copies of the above-designated FERC Form No. 2 as are indicated in the general instructions set out in that form, all properly filled out and verified. One copy of said report should be retained by the correspondent in its files. The conformed copies may be carbon copies, if legible.

(c) This annual report contains the following schedules:

Identification.
General Instructions.
General Information.
Control Over Respondent.
Corporations Controlled by Respondent.
Officers.
Directors.
Security Holders and Voting Powers.
Important Changes During the Year.
Comparative Balance Sheet—Statement A.
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion—Statement B.
Statement of Income for the Year—Statement C.
Statement of Retained Earnings for the Year—Statement D.
Statement of Changes in Financial Position—Statement E.
Nonutility Property.
Accumulated Provision for Depreciation and Amortization of Nonutility Property.
Investments.
Investment in Subsidiary Companies.
Gas Stored.
Prepayments.
Extraordinary Property Losses.
Gas Prepayments Under Purchase Agreements.
Advances for Gas Prior to Initial Deliveries or Commission Certification.
Unamortized Debt Expense, Premium and Discount on Long-Term Debt.
Preliminary Survey and Investigation Charges.
Miscellaneous Deferred Debits.
Unamortized Loss and Gain on Reacquired Debt.
Accumulated Deferred Income Taxes (Account 190).

Capital Stock.
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock.
Other Paid-in Capital.
Discount on Capital Stock.
Capital Stock Expense.
Long-Term Debt.
Securities Issued or Assumed and Securities Refunded or Retired During the Year.
Tax Accrued, Prepaid and Charged During Year.
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes.
Miscellaneous Current and Accrued Liabilities.
Other Deferred Credits.
Undelivered Gas Obligations Under Sales Agreements.
Accumulated Deferred Income Taxes (Accounts 281–283).
Investment Tax Credits Generated and Utilized.
Income from Utility Plant Leased to Others.
Particulars Concerning Certain Income Deduction and Interest Charges Accounts.
Regulatory Commission Expenses.
Charges for Outside Professional and other Consultative Services.
Distribution of Salaries and Wages.
Gas Plant in Service.
Gas Plant Leased to Others.
Gas Plant Held for Future Use.
Production Properties Held for Further Use.
Construction Work in Progress and Completed Construction not Classified—Gas.
Accumulated Provisions for Depreciation of Gas Utility Plant.
Gas Operating Revenues.
Sales of Natural Gas by Communities.
Residential and Commercial Space Heating Customers.
Interruptible, Off Peak, and Firm Sales to Distribution System Industrial Customers.
Field and Main Line Industrial Sales of Natural Gas.
Sales for Resale—Natural Gas.
Revenue from Transportation of Gas of Others—Natural Gas.
Sales of Products Extracted from Natural Gas.
Revenues from Natural Gas Processed by Others.
Gas Operation and Maintenance Expenses.
Number of Gas Department Employees.
Exploration and Development Expenses.
Abandoned Leases.
Gas Purchases.
Exchange Gas Transactions.
Exchange Gas Accounting.
Gas Used in Utility Operations—Credit.
Other Gas Supply Expenses.
Transmission and Compression of Gas by Others.
Miscellaneous General Expenses (Gas).
Construction Overheads—Gas.
General Description of Construction Overhead Procedure.
Depreciation, Depletion, and Amortization of Gas Plant.
Natural Gas Reserves and Land Acreage.
Changes in Estimated Natural Gas Reserves.
Changes in Estimated Hydrocarbon Reserves and Costs, and Net Realizable Value.
Natural Gas Production and Gathering Statistics.
Products Extraction Operations—Natural Gas.
Compressor Stations.
Number of Gas and Oil Wells.
Field and Storage Lines.
Gas Storage.
Transmission Lines.
Liquefied Petroleum Gas Operations.
Transmission System Peak Deliveries.
Auxiliary Peaking Facilities.
Gas Account—Natural Gas.
System Maps.
Research, Development, and Demonstration Activities.
Attestation.

Attachment A, Page 1 of 4

PROPOSED REVISIONS - FORM NO. 2

Title	Schedule Page No.	Retain As Is	Retain Change Threshold	Revise Instructions	Delete Column(s)	Delete Complete Schedule	Explanation
General Instructions	i-ii			X			Instruction 10 - Revise to require CPA certification on only the four basic financial statements, A, C, D, and E.
General Information	101-101A	X					
Control Over Respondent	102	X					
Corporations Controlled by Respondent	103	X					
Officers	104	X					
Directors	105	X					
Security Holders and Voting Power	106-107			X			Revise editorially to reflect Order No. 83.
Important Changes During the Year	108-109	X					
Comparative Balance Sheet - Statement A	110-112	X					
					X		Delete column (a). Expand to allow space for reporting account balances previously grouped and detailed on schedules now proposed for deletion.
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion - Statement B	113	X					
Statement of Income for the Year-Statement C	114-114a			X			Expand to list Accounts 418-418 separately. Delete instruction 7.
Statement of Retained Earnings for the Year-Statement D	117-117A			X			Revise editorially to reflect Order No. 83.
Statement of Changes in Financial Position-Statement E	118-119	X					
Nonutility Property	201		X				Instruction 5 - Add (b) at the balance end of year for Account 121).
Accumulated Provision for Depreciation and Amortization of Nonutility Property	201	X					
Investments	202	X					
Investments in Subsidiary Companies	203	X					
Notes and Accounts Receivable	204	X					
						X	Move beginning and end of year balances to Schedule 110- Comparative Balance Sheet.
Accumulated Provisions for Uncollectible Accounts - Credit	204					X	
Receivables from Associated Companies	206					X	Move beginning and end of year balances to Schedule 110 - Comparative Balance Sheet.
Material and Supplies	207					X	Move beginning and end of year balances to Schedule 110 - Comparative Balance Sheet.
						X	Delete instruction 7 and details for lines 7-11.
Gas Stored	207A			X			
Production Fuel and Oil Stocks	209					X	
Prepayments	230					X	Delete instruction 3 and lines 7-11 allow line 6 to report miscellaneous as a group.
				X			
Miscellaneous Current and Accrued Assets	210	X					
Extraordinary Property Losses	230	X				X	
Gas Prepayments Under Purchase Agreements	230A	X					
Advances for Gas Prior to Initial Deliveries or Commission Certification	230B	X					
Unamortized Debt Expense, Premium, and Discount on Long-Term Debt	231	X					
Preliminary Survey and Investigation Charges	232		X				Instruction 3 - Add: (less than $50,000);
Miscellaneous Deferred Debits	233		X				Instruction 3 - Add: (less than $100,000);

Attachment A, Page 2 of 4

PROPOSED REVISIONS - ITEM NO. 2

Page 2

Title	Schedule Page No.	Ref. Ln	Added Change Threshold	Revise Instructions	Delete Column	Delete Complete Schedule	Explanation
Deferred Losses from Disposition of Utility Plant	214A					X	
Unamortized Loss and Gain on Reacquired Debt	214B	X					
Accumulated Deferred Income Taxes (190)	214C-D	X					
Capital Stock	215	X					
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock and Installments Received on Capital Stock	216	X					
Other Paid-in Capital	217	X					
Discount on Capital Stock	218	X					
Capital Stock Expense	219	X					
Long-Term Debt							
Securities Issued or Assumed and Securities Refunded or Retired During the Year	220	X					
Notes Payable	221					X	Move beginning and end of year balance to Schedule III - Comparative Balance Sheet.
Payables to Associated Companies	221					X	Move beginning and end of year balance to Schedule III - Comparative Balance Sheet.
Taxes Accrued, Prepaid and Charged During the Year	222-222A	X					
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	223	X					
Miscellaneous Current and Accrued Liabilities	224		X				Instruction 3 - Add: (less than $100,000).
Customer Advances for Construction	224					X	
Deferred Gains from Disposition of Utility Plant	224A					X	
Other Deferred Credits	226		X				Instruction 3 - Add: (less than $100,000).
Unamortized Gas Obligations under Sales Agreements	226A	X					
Operating Reserves	228					X	Move beginning and end of year balances to Schedule III - Comparative Balance Sheet
Accumulated Deferred Income Taxes	227-227C	X					
Investment Tax Credits Generated and Utilized	228	X					
Accumulated Deferred Investment Tax Credits	229						
Gain or Loss on Disposition of Property	230					X	
Income from Utility Plant Leased to Others	301	X					
Particulars Concerning Certain Other Income Accounts	303					X	Move account numbers for the year to Schedule III - Statement of Income for the Year. Instruction 3 - Revise to allow for grouping of items less than $100,000. Move Account 420 & (and title) to be included in first sentence of instruction 3.
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	304		X	X			
Expenditures for Certain Civic, Political and Related Activities	305					X	
Extraordinary Items	320						
Common Utility Plant and Expenses	321					X	
Regulatory Commission Expenses	323-323A		X				Instruction 4 - Add: (less than $25,000)
Charges for Outside Professional and Other Consultative Services	324		X				Instructions 1 and 2 - Revise to report only items in excess of $25,000 for both Class A and B
Distribution of Salaries and Wages	325-326	X					

Attachment A, Page 3 of 4

PROPOSED REVISIONS - FERC NO. 2

Page 3

Title	Schedule Page No.	As Tr.	Change Threshold	Major Revision Instructions	Delete Columns	Delete Complete Schedule	Explanation
Gas Plant in Service	301-304						
Gas Plant Leased to Others	305						
Gas Plant Held for Future Use	306		X				Revise Instructions to read $250,000.
Production Properties Held for Future Use	306A		X				Revise Instructions to read $250,000.
Construction Work in Progress and Completed Construction Not Classified - Gas	307		X				Instruction 6 - Add. (less than $500,000)
Accumulated Provision for Depreciation of Gas Utility Plant	308	X					
Accumulated Provision for Amortization and Depletion of Gas Utility Plant:							
Producing Natural Gas Lands and Land Rights						X	
Underground Storage Land and Land Rights	309					X	
Other Gas Plant in Service - Gas Plant Leased to Others, and Gas Plant Held for Future Use	310					X	
Abandonment of Leases	311					X	
Gas Plant Acquisition Adjustments and Accumulated Provision for Amortization of Gas Plant Acquisition Adjustments	312					X	
Gas Operating Reserves	313					X	
Unrecovered Overrun Penalties and Waivers of Penalties	314	X					
Sale of Natural Gas by Communities	315					X	
	316-317						Revise Instructions to report only volumes and operating revenues by State and Class of Customer. Delete columns (a), (d), (f), (i), (j) and (o).
Residential and Commercial Space Heating Customers	318	X					
Interruptible, Off Peak, and Firm Sales to Distribution System Resale Customers	318	X					
Field and Main Line Industrial Sales of Natural Gas	319-320A	X					
Sales for Resale - Natural Gas	321-322	X					
Interdepartmental Sales - Natural Gas	323					X	
Rent from Gas Property and Interdepartmental Rents						X	
Revenue from Transportation of Gas of Others	323					X	
Natural Gas Products Extracted from Natural Gas	325	X					
Revenues from Natural Gas Processed by Others	325	X					
Incidental Gasoline and Oil Sales and Other Gas Revenues	325	X					
Gas Operation and Maintenance Expenses	326					X	
Number of Gas Department Employees	327-334	X					
Lease Rental Charged	335	X					
Exploration and Development Expenses	336-338	X				X	
Abandoned Leases	338	X					
Gas Purchases	338	X				X	
	335 bot						Revise Instructions to reflect reporting by total for each account and resale only columns (d),(i)&(m)
Exchange Gas Transactions	339	X					
Exchange Gas Accounting	340	X					
Gas Used in Utility Operations - Credit	342	X					
Other Gas Supply Expenses	342	X					

Attachment A, Page 4 of 4

PROPOSED REVISIONS - ITEM NO. 2

Page 4

Title	Schedule Page No.	As To	Revise Change Threshold	Revise Instructions	Delete Column	Delete Completing Schedule	Explanation
Transmission and Compression of Gas by Others	841		X	X			Revise instructions and column headings to establish 1 Mcf threshold with lesser amounts allowed to be grouped.
Franchise Requirements	542					X	
Miscellaneous General Expenses (Gas)	843		X				Lines 6 and 8 revise to read $5,000, allowing lesser amounts to be grouped for other expenses. Delete column (d).
Construction Overheads - Gas	843				X		
General Description of Construction Overhead Procedure	544						
Depreciation, Depletion and Amortization of Gas Plant	345 348A	X		X	X		Revise instructions to reflect the deletion of Sections B, page 336, and revisions to Section C, reporting by functions in total, retain only columns (b) and (d).
Natural Gas Reserves and Land Acreage	347-348	X					
Changes in Estimated Natural Gas Reserves	349	X					
Changes in Estimated Hydrocarbon Reserves and Costs	348A 349A	X					
Natural Gas Reserves Available from Purchase Agreements	350 351					X	
Natural Gas Production and Gathering Statistics	352 352A				X		Revise instructions to reflect the deletion of columns (c) through (g). Revise title to reflect the deletion.
Products Extraction Operations - Natural Gas	354 355			X	X		Revise instructions to reflect the deletion of columns (c) through (j), details by plant.
Compressor Stations	554 557	X		X			
Number of Gas and Oil Wells	558						Delete Instruction 5 - regarding other than full ownership of wells disclosure.
Field and Storage Lines	559			X	X		Revise instructions to reflect the deletion of columns (c) through (g), diameter of pipe.
Gas Storage	560-561B			X	X		Revise instructions to reflect the deletion of columns (c) through (g), diameter of pipe.
Transmission Lines	562			X	X		Revise instructions to reflect the deletion of columns (c) through (g), diameter of pipe.
Manufactured Gas Production Statistics	563	X				X	
Liquified Petroleum Gas Operations	564	X					
Transmission System Peak Deliveries	565	X					
Auxiliary Peaking Facilities	566	X					
Gas Account - Natural Gas	568 569	X					
Purchased Gas Expenses Occurring on the Pipeline System	570	X				X	
System Map	571						
Research, Development and Demonstration Activities	327-327A	X					
Footnotes	573	X					

¶ 32,073 Revision to Annual Report for Electric Utilities, Licensees and Others (Class A and Class B): Form No. 1

45 F. R. 47705 (July 16, 1980).

18 CFR Part 141

[Docket No. RM80-55]

Revision to Annual Report for Electric Utilities, Licensees and Others (Class A and Class B): Form No. 1

Issued: July 10, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it proposes to revise its annual report, Form No. 1, "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)" (18 CFR 141.1). The proposed amendments would eliminate certain data elements which the Commission no longer needs to carry out its regulatory functions. The proposed changes are a product of the Commission's ongoing effort to eliminate unnecessary reporting burdens.

DATE: Comments are due by September 8, 1980.

ADDRESS: Comments on this Notice should be addressed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80-55.

FOR FURTHER INFORMATION CONTACT:

James Kitchen, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 3408N, Washington, D.C. 20426 (202) 357-9212.

Elaine M. Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 3405N, Washington, D.C. 20426 (202) 357-9190.

SUPPLEMENTARY INFORMATION:

I. Background

The Federal Energy Regulatory Commission (Commission) is engaged in an ongoing effort to eliminate unnecessary reporting burdens. This rulemaking to amend Form No. 1, "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B),"[1] is part of that effort, and reflects a new evaluation of the data needed by the Commission to carry out its regulatory functions. The proposed revisions for the form should result in a significant reduction in the respondents' burdens.*

Form No. 1 collects information annually from electric utility companies and certian other hydroelectric production sources. The data primarily include general corporate information; summary financial data; balance sheet supporting data; income statement supporting data; and electric plant, sales, operating and statistical data.[2]

The Commission has reviewed Form No. 1 in light of its regulatory responsibilites, and has determined that it no longer needs certain elements of the data collected. The proposed

[1] A Class A electric utility is one having annual electric operating revenues of $2,500,000 or more. A Class B electric utility is one having annual electric operating revenues of $1,000,000 or more but less than $2,500,000. This classification criteria has not been examined for this rulemaking; it will, however, be the subject of a separate rulemaking.

* FERC Form No. 1 (Attachment B) is not being printed in the **Federal Register**. Copies are available in the Office of Public Information.

[2] The Commission is authorized to prescribe the reporting requirements of Form No. 1 pursuant to sections 3 (2)-(5) and (7), 304 and 309 of the Federal Power Act (16 U.S.C. §§ 796(3)-796(5), 796(7), 825c, and 825h).

deletions would cause an estimated 28 percent reduction in the current reporting burden for the form.[3]

The Energy Information Administration (EIA), however, may decide on behalf of itself or other sponsors within the Department of Energy to continue the collection of some data proposed for deletion herein. If EIA should make such a determination during this rulemaking proceeding, the Commission would issued a Final Rule based on this Notice with a delayed effective date. This would provide EIA (or any other potentially interested agency) a period of time in which to justify the need for the data and receive the approval for collection of such data under the agency's own authority.

II. Summary of Revisions

Fifty-five of the schedules in Form No. 1 have not been amended.[4] The following is a brief summary of the Commission's proposed revisions to Form No. 1:[5]

a. Eliminate the requirement of CPA certification from 14 of the 18 schedules presently designated for such certification.

b. Establish specific threshold reporting levels on 8 schedules.

c. Revise the reporting instructions on 9 schedules.

d. Delete entire data columns from 4 schedules.

e. Delete 35 schedules in their entirety.

The proposed amendments to Form No. 1, as outlined above, are not proposed for certain modified versions of the form which are filed by various Government entities, including the Army Corps of Engineers,[6] the Department of Interior and various Department of Energy power marketing administrations. Any changes in these modified forms will be considered independently of this rulemaking.

III. Comment Procedure

The Commission invites interested persons to submit written comments on this proposal. Copies of all comments will be furnished to EIA for its use. The Commission specificially requests that the comments address the following questions:

1. a. Do the proposed revisions or elimination of data affect any Commission or State regulatory functions?

b. Will State agencies now utilizing this report form in the exercise of their own regulatory responsibilities agree to reduce their reporting requirements concurrently?

2. Is there any reason for continued collection of the data for the purposes of another Federal agency? Suggestions for the continued collection of data which have been proposed for elimination from the present Form No. 1 should identify the proper agency and the purpose for the proposed collection of the data.

3. What cost savings are likely to result from the proposed elimination of the 14 CPA certification? [7]

4. What are the merits of using a percentage of the year end account balance rather than a selected fixed dollar figure in establishing a threshold for "minor items?"

5. What is the effect of deleting the INDEX from the back of the report form? [8]

Interested persons wishing to comment on this proposal should submit copies of their comments to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street,

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[3] This is a conservative estimate, in that the data requirements in many of the schedules to be deleted are open-ended. As a result, some responses to these schedules can vary between zero and several hundred lines.

[4] Schedules 431 through 502 have not been reviewed in connection with this rulemaking. They will be examined during the Commission's reevaluation of other related forms. Comments are, nevertheless, solicited at this time with reference to these schedules.

[5] *See* Attachment A for a chart of the proposed revisions to Form No. 1. *See* Attachment B for Form No. 1 with proposed revisions.

[6] The Army Corps of Engineers form has been on officially designated as FPC Form No. 1002.

[7] Responses to this question are especially requested from CPA firms.

N.E., Washington, D.C. 20426 and should refer to Docket No. RM80-55. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, September 8, 1980, will be considered by the Commission prior to promulgation of final regulations. Pursuant to the Federal Reports Act, 44 U.S.C. 3501-3511, these proposed revisions will be considered by the Office of Management and Budget for ultimate clearance. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection during regular business hours in the Commissions's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(Federal Power Act, as amended, 16 U.S.C. 792-828(c); Department of Energy Organization Act, 42 U.S.C. 7101-7352; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to revise Form No. 1, "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)," prescribed by § 141.1, Chapter I, Title 18 of the Code of Federal Regulations as set out in Attachment B.

In addition, in consideration of the foregoing, the Commission proposes to revise Part 141 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 141—STATEMENTS AND REPORTS (SCHEDULES)

1. Part 141—Statement and Reports (Schedules)—is amended in the Table of Contents and in the text of the regulations by revising § 141.1 to read as follows:

§ 141.1 FERC form No. 1, annual report for electric utilities, licensees and others (class A and class B).

(a) The form of annual report for class A and class B electric utilities, licensees and others, designated herein as FERC Form No. 1 is prescribed for the year 1980 and thereafter.

(b)(1) Each class A electric utility, licensee, and other entity, i.e., each corporation, person, or licensee as defined in section 3 of the Federal Power Act (16 U.S.C. 792-828(c)), including any agency, authority or other legal entity or instrumentality and any agency, authority or instrumentality of the United States engaged in generation, transmission, distribution, or sale of electric energy, however produced, throughout the United States and its possessions, having annual electric operating revenues of $2,500,000 or more, whether or not the jurisdiction of the Commission is otherwise involved, shall prepare and file with the Commission for the year beginning January 1, 1980, or subsequently during the calendar year 1980 if its established fiscal year is other than the calendar year, and for each year thereafter, on or before the last day of the third month following the close of the calendar year or other established fiscal year, an original and such number of conformed copies of the above designated FERC Form No. 1 as are indicated in the General Instructions set out in that form, all properly filled out and verified. One copy of said report should be retained by the correspondent in its files. The conformed copies may be carbon copies, if legible.

(2) This report form is not prescribed for municipalities as defined in section 3 of the Federal Power Act; i.e., a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of

*Form No. 1 contains a list of Schedules at pages iii through v, including the page locations of each schedule. Each of the finanical statements (balance sheet and income statement) contains a column for the page number of the statement's supporting schedule.

developing, transmitting, utilizing, or distributing power.

(c)(1) Each class B electric utility, licensee, and other entity, i.e., each corporation, person, or licensee as defined in section 3 of the Federal Power Act, including any agency, authority or other legal entity or instrumentality and any agency, authority or instrumentality of the United States engaged in generation, transmission, distribution or sale of electric energy, however produced, throughout the United States and its possessions, having annual electric operating revenues of more than $1,000,000 but less than $2,500,000, whether or not the jurisdiction of the Commission is otherwise involved, shall prepare and file with the Commission for the year beginning January 1, 1980, or subsequently during the calendar year 1980, if its established fiscal year is other than the calendar year, and for each year thereafter, on or before the last day of the third month following the close of the calendar year or other established fiscal year, an original and such number of conformed copies of the above-designated FERC Form No. 1 as are indicated in the General Instructions set out in that form, all properly filled out and verified. One copy of said report should be retained by the correspondent in its files. The conformed copies may be carbon copies, if legible.

(2) This report form is not prescribed for municipalities as defined in section 3 of the Federal Power Act; i.e., a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power.

(d) This annual report contains the following schedules:

Identification.
General Instruction.
General Information.
Control Over Respondent.
Corporations Controlled by Respondent.
Officers.
Directors.
Security Holders and Voting Powers.
Important Changes During the Year.
Comparative Balance Sheet—Statement A.
Notes to Balance Sheet—Statement A (Continued).
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion—Statement B.
Statement of Income for the Year—Statement C.
Notes to Statement of Income—Statement C (Continued).
Statement of Retained Earnings for Year—Statement D.
Statement of Changes in Financial Position—Statement E.
Nuclear Fuel Materials.
Nonutility Property.
Investment in Subsidiary Companies.
Materials and Supplies.
Extraordinary Property Losses.
Unamortized Debt Expense, Premium and Discount on Long-Term Debt.
Miscellaneous Deferred Debits.
Accumulated Deferred Income Taxes (Account 190).
Capital Stock.
Capital Stock, Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock.
Other Paid-in Capital.
Discount on Capital Stock.
Capital Stock Expense.
Long-Term Debt.
Securities Issued or Assumed and Securities Refunded or Retired During the Year.
Taxes Accrued, Prepaid and Charged During Year.
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes.
Other Deferred Credits.
Accumulated Deferred Income Taxes.
Accumulated Deferred Investment Tax Credits.
Particulars Concerning Certain Income Deduction and Interest Charges Accounts.
Common Utility Plant and Expenses.
Regulatory Commission Expenses.
Distribution of Salaries and Wages.
Electric Plant in Service.
Electric Plant Leased to Others.
Electric Plant Held for Future Use.
Construction Work in Progress—Electric.
Accumulated Provision for Depreciation of Electric Utility Plant.
Electric Operating Revenues.
Sales for Resale.
Sales of Electricity by Rate Schedules.
Electric Operation and Maintenance Expenses.
Purchased Power.
Interchange Power.

Transmission of Electricity for or by Others.
Miscellaneous General Expenses.
Construction Overheads—Electric.
General Description of Construction Overhead Procedure.
Depreciation and Amortization of Electric Plant.
Electric Energy Account.
Monthly Peaks and Output.
Steam-Electric Generating Plant Statistics (Large Plants).
Steam-Electric Generating Plant Statistics (Large Plants) Average Annual Heat Rates and Corresponding Net kwh Output for Most Efficient Generating Units.
Hydroelectric Generating Plant Statistics (Large Plants).
Pumped Storage Generating Plant Statistics (Large Plants).
Generating Plant Statistics (Small Plants).
Changes Made or Scheduled to be Made in Generating Plant Capacities.
Steam-Electric Generating Plants.
Hydroelectric Generating Plants.
Pumped Storage Generating Plants.
Internal-Combustion Engine and Gas-Turbine Generating Plants.
Transmission Line Statistics.
Transmission Lines Added During Year.
Substations.
Electric Distribution Meters and Line Transformers.
Research, Development, and Demonstration Activities.
Environmental Protection Facilities.
Environmental Protection Expenses.
Attestation.

Attachment A.—Proposed Revisions, Form No. 1

Title	Schedule page No.	Retain— As is	Retain— Change threshold	Retain— Revise instructions	Retain— Delete columns	Delete complete schedule	Explanation
General Instructions	i-ii			X			Instruction 14—Revise to require CPA certification on only the four basic financial statements A, C, D, and E.
General Information	101-101A			X			Delete instruction 5(d).
Control Over Respondent	102	X					
Corporations Controlled by Respondent	103	X					
Officers	104	X					
Directors	105			X			Revise editorially to reflect Order No. 57.
Security Holders and Voting Powers	106-107	X					
Important Changes During the Year	108-109	X					
Comparative Balance Sheet—Statement A	110-112				X		Delete column (e). Expand to allow space for reporting account balances previously grouped and detailed on schedules now proposed for deletion.
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion—Statement B	113	X					
Statement of Income for the Year—Statement C	114-116A			X			Expand to list Accounts 415-418 separately. Delete Instruction 7.
Statement of Retained Earnings for the Year—Statement D	117-117A			X			Revise editorially to reflect Order No. 53.
Statement of Changes in Financial Position—Statement E	118-119	X					
Nuclear Fuel Materials	200	X					
Nonutility Property	201		X				Instruction 5—Add: (5% of the balance end of year for Account 121).
Accumulated Provision for Depreciation and Amortization of Nonutility Property	201					X	
Investments	202					X	
Investment in Subsidiary Companies	203	X					
Notes and Accounts Receivable	204					X	Move beginning and end of year balance to Schedule 110—Comparative Balance Sheet.
Accumulated Provisions for Uncollectible Accounts—Cr.	204					X	
Receivables from Associated Companies	206					X	Move beginning and end of year balance to Schedule 110—Comparative Balance Sheet.

Attachment A.—*Proposed Revisions, Form No. 1*—Continued

Title	Schedule page No.	Retain— As is	Retain— Change threshold	Retain— Revise instructions	Retain— Delete columns	Delete complete schedule	Explanation
Material and Supplies	207			X			Revise Instruction 1, to indicate reporting by functional classifications as preprinted in (a).
Production Fuel and Oil Stocks	209					X	
Miscellaneous Current and Accrued Assets	210					X	
Extraordinary Property Losses	210	X					
Unamortized Debt Expense, Premium and Discount on Long-Term Debt.	211	X					
Preliminary Survey and Investigation Charges.	212					X	
Miscellaneous Deferred Debits	214		X				Instruction 3—Add: (1% of the balance end of year for Account 186 or amounts less than $50,000 whichever is less).
Deferred Losses from Disposition of Utility Plant.	214A					X	
Unamortized Loss and Gain on Required Debt.	214B					X	
Accumulated Deferred Income Taxes (190)	214C-D				X		Delete columns (c) through (j). Retain (a), (b), and (k) only.
Capital Stock	215	X					
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock and Installments Received on Capital Stock.	216	X					
Other Paid-in Capital	217	X					
Discount on Capital Stock	218	X					
Capital Stock Expense	218	X					
Long-Term Debt	219	X					
Securities Issued or Assumed and Securities Refunded or Retired During the Year.	220	X					
Notes Payable	221					X	Move Beginning and end of year balance to Schedule 111—Comparative Balance Sheet.
Payables to Associated Companies	221					X	Move Beginning and end of year balance to Schedule 111—Comparative Balance Sheet.
Taxes Accrued, Prepaid and Charged During the Year.	222-222A	X					
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes.	223	X					
Miscellaneous Current and Accrued Liabilities	224					X	
Customer Advances for Construction	224					X	

Title	Schedule page No.	Retain— As is	Change threshold	Revise instructions	Delete columns	Delete complete schedule	Explanation
Deferred Gains from Disposition of Utility Plant	224A					X	
Other Deferred Credits	225		X				Instruction 3—Add (1% of the balance end of the year for Account 253 or amounts less than $50,000 whichever is less)
Operating Reserves	226					X	Move beginning and end of year balances to Schedule 111—Comparative Balance Sheet
Accumulated Deferred Income Taxes	227-227E	X					
Investment Tax Credits Generated and Utilized	228					X	
Accumulated Deferred Investment Tax Credits	229	X					
Gain or Loss on Disposition of Property	300					X	
Income from Utility Plant Leased to Others	301					X	
Particulars Concerning Certain Other Income Accounts	303					X	Move Account amounts for the year to Schedule 116A—Statement of Income for the Year
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	304		X	X			Instruction 3—Revise to allow for grouping items less than 5% of each account total for the year. Move Account 426.4 (and title) to be included in first sentence of instruction 3
Expenditures for Certain Civic, Political and Related Activities	305					X	
Extraordinary Items	306					X	
Common Utility Plant and Expenses	351	X					
Regulatory Commission Expenses	353-353A		X				Instruction 6—Add (less than $25,000).
Charges for Outside Professional and Other Consultative Services	354					X	
Distribution of Salaries and Wages	355-356	X					
Electric Plant in Service	401-403	X				X	
Fish and Wildlife and Recreation Plants	403a						
Electric Plant Leased to Others	404	X					
Electric Plant Held for Future Use	405		X				Revise instructions to read $250,000

Attachment A.—*Proposed Revisions, Form No. 1*—Continued

Title	Schedule page No.	Retain— As is	Change threshold	Revise instructions	Delete columns	Delete complete schedule	Explanation
Construction Work in Progress and Completed Construction not Classified—Electric.	406		X	X	X		Instruction 4—Add. (5% of the balance end of year for Account 107). Delete column (c) Account 106 and revise instructions to reflect the deletion of Account 106 from the schedule.
Plant Acquisition Adjustments and Accumulated Provision for Amortization of Plant Acquisition Adjustments.	407					X	
Accumulated Provision for Depreciation of Electric Utility Plant.	408	X					
Electric Operating Revenues	409			X			Delete the requirement at bottom of schedule for listing the "Total All Electric" Customers.
Sales of Electricity—By Communities	410-411					X	
Sales for Resale	412-413	X					
Sales of Electricity by Rate Schedules	414	X					
Sales to Railroads and Railways and Interdepartmental Sales.	415					X	
Rent from Electric Property and Interdepartmental Rents.	415					X	
Sales of Water and Water Power	416					X	
Miscellaneous Service Revenues and Other Electric Revenues.	416					X	
Electric Operation and Maintenance Expenses.	417-420	X					
Number of Electric Department Employees	420					X	
Operation and Maintenance Expenses of Fish and Wildlife and Recreation Operations.	420a					X	
Lease Rentals Charged	421A-421D					X	
Purchased Power	422-423	X					
Interchange Power	424	X					
Transmission of Electricity for or by Others	425	X					
Franchise Requirements						X	
Miscellaneous General Expenses—Electric	427		X				Revise lines 6 and 7 to read: 5% of the amount for the year for Account 930.2.
Construction Overhead—Electric	427				X		Delete column (d).
General Description of Construction Overhead procedure.	428	X					
Depreciation and Amortization of Electric Plant.	429-430A	X					

Attachment A.—*Proposed Revisions, Form No. 1*—Continued

Title	Schedule page No.	Retain— As is	Change threshold	Revise instructions	Delete columns	Delete complete schedule	Explanation
Electric Energy Account	431	X					
Monthly Peaks and Output	431	X					
Steam-Electric Generating Plant Statistics (Large).	432-432a	X					
Steam-Electric Generating Plant Statistics (Large Plant) Average Annual Heat Rates and Corresponding Net Kwh Output for Most Efficient Generating Net Kwh Output for Most Efficient Generating Units/Total System Steam Plants.	432b	X					
Hydroelectric Generating Plant Statistics (Large).	433a-433b	X					
Pumped Storage Generating Plant Statistics (Large).	433c-433d	X					
Generating Plant Statistics (Small Plant)	434	X					
Changes Made or Scheduled to be Made in Generating Plant Capacities.	435	X					
Steam-Electric Generating Plants	436-437	X					
Hydroelectric Generating Plants	438-439	X					
Pumped Storage Generating Plants	439a-439c	X					
Internal-Combustion Engine and Gas-Turbine Generating Plants.	440-441	X					
Transmission Line Statistics	442-443	X					
Transmission Lines Added During Year	444	X					
Substations	445	X					
Electric Distribution Meters and Line Transformers.	447	X					
Research, Development and Demonstration Activities.	48-448A	X					
Environmental Protection Facilities	501	X					
Environmental Protection Expenses	502	X					
Attestation	503	X					
Index						X	

¶ 32,074 High-Cost Natural Gas Produced From Wells Drilled in Deep Water

45 F. R. 47863 (July 17, 1980)

18 CFR Parts 271, 273 and 274

[Docket No. RM80-38]

High-Cost Natural Gas Produced From Wells Drilled in Deep Water

Issued July 11, 1980

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission gives notice that it proposes to adopt regulations under section 107(c)(5) of the Natural Gas Policy Act of 1978 to establish as high-cost gas certain gas produced in deep water and to set an incentive price for such gas. The primary qualification for the gas under the proposal is that it be produced from acreage submerged at water depths of 500 feet or greater. The proposed price is 150 percent of the otherwise applicable maximum lawful price.

DATE: Written comments are due by August 11, 1980.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. Reference Docket No. RM80-38.

FOR FURTHER INFORMATION CONTACT:

Vic Zabel, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, Room 6100-C, 825 North Capitol Street, NE., Washington, D.C. 20428, (202) 357-8557; or

Colette Bohatch, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100-B, 825 North Capitol Street, NE., Washington, D.C. 20428, (202) 357-8140.

I. Introduction

The Federal Energy Regulatory Commission (Commission) proposes in this rulemaking to establish as high-cost gas certain gas produced in deep water and to set an incentive price for such gas. The primary qualification for the gas as the rule is proposed is that it be produced from acreage submerged at water depths of 500 feet or greater. The proposed rule not only identifies the submerged acreage which qualifies under the rule but also describes the application requirements and procedures for obtaining a well category determination.

II. Background

The Commission is authorized pursuant to section 107(b) of the Natural Gas Policy Act of 1978 (NGPA)[1] (15 U.S.C. § 3317) to prescribe a maximum lawful price necessary to provide reasonable incentives for the production of gas which the Commission determines, under section 107(c)(5), to be high-cost gas. Five categories of high-cost gas are described in section 107(c)[2];

[1] Section 107(b) provides that:

The Commission may, by rule or order, prescribe a maximum lawful price, applicable to any first sale of any high-cost natural gas, which exceeds the otherwise applicable maximum lawful price to the extent that such special price is necessary to provide reasonable incentives for the production of such high-cost natural gas.

[2] Section 107(c) (15 U.S.C. § 3317) reads as follows:

For purposes of this section, the term "high-cost natural gas" means natural gas determined in accordance with section 503 to be—

(1) produced from any well the surface drilling of which began on or after February 19, 1977, if such production is from a completion location which is located at a depth of more than 15,000 feet;

(2) produced from geopressured brine;

(3) occluded natural gas produced from coal seams;

(4) produced from Devonian shale; and

(5) produced under such other conditions as the Commission determines to present extraordinary risks or costs.

r of these categories, subparagraph 1) through (4), have been deregulated ccordance with section 121.[3] The ntification and pricing of gas which is ered by the fifth category is left to discretion of the Commission.

a Notice of Inquiry, issued on June 1979, regarding implementation of tion 107 (b) and (c),[4] the Commission uested, in part, that the public gest categories of gas which might lify under section 107(c)(5) for an entive price. After reviewing the ments received, the Commission blished a rulemaking to consider ether gas produced from tight nations was qualified for an entive price. The tight formation making is presently in the final stage levelopment.[5] In this rulemaking, also outgrowth of the Notice of Inquiry, Commission is considering whether produced in deep water is qualified an incentive price and, if so, what price should be.

s we have learned from the tight nation rulemaking, setting technical ameters for the qualified gas is a cess over-shadowed in difficulty only the economic analysis which is essary to arrive at an appropriate entive price. Here too, we are iating a similar process for sideration of deep-water gas. The owing discussion, which outlines our roach describes the most significant tures of the proposed rule and cusses the outstanding issues on ich we encourage the public to ment.

Summary of the Proposed Rule

The proposed rule provides an entive price of 150% of the otherwise plicable maximum lawful price for gas duced in deep water. Under the posal, "deep-water gas" is defined as :

(1) which is produced from a well the surface drilling of which began on or after May 28, 1980;

(2) which is produced from qualified submerged acreage; and

(3) for the first sale of which a negotiated contract price is in effect.

The Commission proposes to identify qualifying submerged acreage by reference to the 500-foot contour line indicated on maps published and maintained by the National Oceanic and Atmospheric Administration of the Department of Commerce. Any blocks leased by the Department of the Interior which straddle or are seaward of the 500-foot contour would be qualified acreage. The qualification of blocks will eliminate the necessity for an applicant to verify water depth on a well-by-well basis. Consequently, gas produced from such acreage will meet the qualified acreage requirement regardless of the exact water depth of a specific well.

IV. Issues

Several comments regarding deep-water gas were submitted by the public in response to the Notice of Inquiry referred to above.

A. *Water Depth and Necessary Incentive Price.*

All the commenters agreed that production of gas from submerged acreage becomes more costly as offshore production operations move seaward; *i.e.*, the deeper the water, the greater the costs and risks. Commenters recommended a range of depths from 250 to 500 feet for which costs and risks begin to escalate rapidly because specially designed exploratory vessels, drilling and production platforms, and other equipment are required. Some of the special design considerations noted were weather conditions, ocean currents, water surface conditions, and topography of the seabed.

Section 121 provides for price deregulation of -cost gas described in section 107(c)(1) through on the effective date of the incremental pricing , which was November 1, 1979.
Docket No. RM79-44, 44 *Fed. Reg.* 34069.

[4] *See*, "Interim Rule and Request for Further Comment," Docket No. RM79-76, issued February 20, 1980.

Guidance regarding appropriate water depth is found also in the legislative history of the NGPA. The NGPA Conference Report states as follows:

The Commission may determine that natural gas produced from submerged acreage located beneath more than 500 feet of water [qualifies] as natural gas produced under such conditions as present extraordinary risks or costs. H. Rept. No. 95–1752, 95th Cong., 2d Sess. 87 (1978).

Based upon the Conferees' suggestion and the comments submitted by the public, we have tentatively concluded that the 500-foot water depth is an appropriate starting point for public discussion.

Although the costs and risks of gas production generally escalate as offshore operations move seaward, the Commission must specifically determine the depth at which costs and risks reach the point where higher incentive prices are necessary to stimulate increased drilling activity.

The Commission has arrived at a preliminary conclusion that because some gas is already being produced in water depths less than 500 feet an incentive price is not necessary to stimulate production in the shallower depths. Gas production has not been developed to any great extent beyond the 500-foot depth, even though technology has provided equipment and platforms designed to function in water depths greater than 500 feet. Offshore production operations which have been established beyond this depth predominantly produce oil. We believe that gas production, like oil production, can also be stimulated beyond the 500-foot water depth if it is afforded an appropriate price incentive.

The Commission needs to obtain data, however, to determine what price is necessary to compensate producers for the costs and risks associated with producing gas beyond the 500-foot depth. Although we have preliminarily proposed the 500-foot water depth as the cut-off, we will consider suggestions, if supported by adequate documentation that another depth may be more appropriate under this rule.

The Commission has several options in selecting a final depth: we could establish a specific depth such as the proposed 500-foot depth and set a single incentive price or we could establish several depths and provide a graduated incentive price for each depth. We request comment on these alternatives and, with reference to the single depth and price, inquire whether, for example a 300 foot rather than a 500 foot cut-off would be more appropriate, and if so, what incentive price should be applied. Specifically, the Commission invites the submission of data which demonstrates the extent to which costs increase as water depths increase.

In making these decisions, we must not only consider whether there are extraordinary costs or risks associated with production, but must also determine the extent to which a special price is "necessary to provide reasonable incentives" for production of the category of gas in question.

Several bases for establishing incentive prices were suggested by commenters. Some proposed pegging the price of deep-water gas to the prices for alternative fuels displaced by the use of such gas. Others proposed tying the maximum lawful price to the section 102 price. Various pricing approaches, such as stairstep, area rate, and variable rate were also suggested.

The Commission has considered several approaches for establishing incentive prices under section 107(c)(5). Such approaches include comparing relative costs of the various categories of gas, determining the supply response which can be expected at various prices, establishing a fixed premium over the otherwise applicable maximum lawful price, or establishing the price based on policy considerations, for example, indexing it to the commodity value of gas.

The statute does not fully describe the Commission's responsibilities in establishing an incentive price.

wever, some guidance as to the tutory standard for price justification rovided in the Conference Report ompanying the NGPA which states t the incentive prices need not be st-based in nature, and do not uire cost justification." H. Rept. No. 1752, 95th Cong. 2d Sess., 88 (1978). s statement implies that the prices ablished by the Commission for ncost gas need not be based on costs he sense of conventional public ity ratemaking. Clearly, the nmission has the authority to exceed h a cost-based price and the erwise applicable maximum lawful e in satisfying the statutory standard price justification. The Commission uests that comments address what roach the Commission should take in nulating an incentive price ceiling. he Commission also requests that a be submitted that will indicate the tive costs of producing from deep er compared to shallower waters. As stated in the interim rule on tight nations, we believe that sideration of costs is relevant, if not erequisite, to establishing a price cessary" to create "reasonable" ntives for gas production, because price must exceed anticipated costs rder to provide an incentive for duction.[6]

or purposes for this proposal, the mission has preliminarily concluded the incentive price for gas drilled 500 feet of water should provide a premium above the incentive price rwise permitted by Congress.[7] This ng reflects information received in context of another proceeding that relative costs of drilling for gas in water are approximately one and a times higher than of the costs of ing in shallower water depths.[8] le the Commission does not intend the incentive price match only the costs associated with developing such gas, it must be able to compare relative costs to determine whether the 50% premium over the otherwise applicable maximum lawful price is necessary.

Gas which qualifies for the incentive price under this proposed rule is currently subject to section 102 or 104. The proposed rule may have a different impact upon gas production depending upon its otherwise applicable price category and the stage of lease development. Production of gas from submerged acreage which has not yet been leased will receive little stimulation from this rule. This gas is covered by section 102(c)(1)(A) for which the price will be deregulated in 1985 in accordance with section 121(a)(1). Judging from the lag time between lease sale and inception of production, this gas will probably not be available for delivery until at least the mid 1980's at which time its price will be deregulated. For these reasons, we do not anticipate that this rule will result in a stimulation of gas production from such acreage.

We anticipate some impact upon the following three categories of OCS gas. The first category would include gas from newly drilled wells on presently existing "new" leases, *i.e.*, leases entered into after April 20, 1977, as defined in section 2(9). This gas is priced in accordance with section 102(c)(1)(A) for which the price will be deregulated in 1985. The second category would include gas from newly drilled wells produced from reservoirs discovered on or after July 27, 1976 on old leases as defined in section 2(10). This gas is priced under section 102(d) and is not scheduled for deregulation under the NGPA.

The third category would include gas produced through newly drilled wells on

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e, "Interim Rule and Request for Further nents," Docket No. RM79-76, issued February 80, *mimeo.*, pp. 36-44.

as which qualifies for the incentive price under roposed rule is currently subject either to the n 102 or 104 maximum lawful price.

[8] Sun Gas Company filed with the Commission a 1975 study of the comparative costs of drilling in various water depths. Sun concluded that the costs of drilling in deeper water were 150% more expensive than drilling in shallower water. Docket No. RM75-14 (filed May 23, 1975).

old leases, for which production from old reservoirs would receive the section 104 price. With regard to this category, some of these leases are at an advanced stage of development so that, we believe, giving an incentive price would stimulate production in the short term.

We are unable, however, to quantify for any of the three categories the pace at which such additional development will proceed under the proposed rule or to ascertain at this point whether a higher incentive price would encourage more rapid development of presently undeveloped or unleased blocks.

We invite the public to assist the Commission in determining what gas should qualify as deep-water gas and what the incentive price should be. To obtain information which will enable the Commission to establish an incentive price, we have formulated the following questions on which the commenters should focus:

(1) Is the 150% incentive price necessary to stimulate OCS gas production in 500-foot depths? If not, what price is necessary?

(2) Should the depth limit be changed to 300 feet? If so, what incentive price is necesary?

(3) In the alternative, should the incentive price be graduated to correspond to the depth of the water, so that different intervals of submerged acreage will qualify for different prices? If so, what depths and what prices?

(4) What would be the impact of choosing any alternatives advocated in response to questions 1 through 3 on the four different categories of OCS gas production as to the incremental amount that will be produced and the pace of such increase in production?

(5) What basis is appropriate for the setting an incentive price and why? Reconcile any suggestions with the Conferees' statement that "such special ceiling prices are not intended to be cost-based in nature, and do not require cost justification" H. Rept. No. 95–1752, 95th Cong., 2d Sess., 88 (1978).

B. Interim Collections.

The Commission proposes to apply interim collection provisions of Part 273 to deep-water gas. The incentive price may be collected retroactively for deliveries on or after May 28, 1980.

C. Well Qualifications.

The Commission proposes that the surface drilling of a qualifying well must begin on or after May 28, 1980, the date the Commission first announced to the public that it was considering an incentive price for deep-water gas. This cut-off date complies with the Conference Report which states that the Conferees intended that price incentives be created in advance of drilling. H. Rept. No. 95–1752, 95th Cong., 2d Sess., 88 (1978). It is obvious that a producer that commenced drilling prior to the May 28th announcement did not need an incentive price for that production. The Commission welcomes comment on this requirement.

Both associated and non-associated gas are eligible for the incentive price proposed in this rule. We encourage comments as to whether the pricing incentive should be extended only to nonassociated gas. Comments advocating that the incentive price be limited to non-associated gas should support that position and should indicate what maximum amount of oil production, if any, should be permitted.

The proposed definition of "deep-water gas" includes the requirement that the first sale of such gas be subject to a negotiated contract price. A "negotiated contract price" is defined in § 271.703(e) of the Commission's interim regulations as any price established by a contract that specifically refers to the Commission's pricing authority under section 107 of the NGPA or that contains a fixed rate or a fixed escalator clause. This provision also applies to tight formation gas and is proposed here for the same reasons discussed in the

erim rule on tight formations.[9] In ef, the Commission believes that this quirement insures that the maximum vful price serves as an incentive for e production of additional deep-water s rather than as a windfall.

Environmental Issues.

The Commission staff is presently eparing an environmental assessment this proposed rulemaking. Although e staff has not yet completed its vironmental assessment, preliminary lications are that the rulemaking uld not be a major Federal action nificantly affecting the quality of the man environment and that an vironmental Impact Statement will t be necessary. If the staff determines the final analysis that this rulemaking not a major Federal action, it will epare a finding of no significant pact. This finding and any related vironmental documents will be placed the public file in this docket intained by the Commission's Office Public Information. The vironmental assessment completed by r staff will be made available before e final rule in this docket is issued. Comments are requested on any vironmental issues. Comments should fully explained, and, if possible, ostantiated with data.

Written Comment Procedures

nterested persons may comment on s proposed rulemaking by submitting itten data, views or arguments to the fice of the Secretary, Federal Energy gulatory Commission, 825 North pitol Street, N.E., Washington, D.C. 426, on or before August 11, 1980. Each rson submitting a comment should dicate that the comments are being omitted in Docket No. RM80-38, and uld give reasons including any pporting data for any commendations. Comments should o indicate the name, title, mailing dress, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours. A date and location for public hearings on this rulemaking may be announced in the near future.

(Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 *Fed. Reg.* 46267; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

In consideration of the foregoing, the Commission proposes to amend Parts 271, 273 and 274 Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 271—CEILING PRICES

1. Section 271.701 is revised to read as follows:

§ 271.701 Applicability.

This subpart implements section 107(b) and (c)(5) of the NGPA and applies to the first sale of natural gas which a jurisdictional agency determines is new tight formation gas or deep-water gas.

2. Section 271.702 is amended by adding paragraph (a) to read as follows:

§ 271.702 Maximum lawful prices.

(a) *Deep-water gas.* (1) The maximum lawful price, per MMBtu, for the first sale of deep-water gas shall be the lesser of:

(ii) The negotiated contract price; or

[9] See, "Interim Rule and Request for Further nment," February 20, 1980, Docket No. RM79-76, neo, pp. 34-38.

(ii) 150 percent of the otherwise applicable maximum lawful price specified in Tables I and II of § 271.101(a).

(2) *Cross reference.* For the special rule on retroactive collection for deep-water gas, see § 273.204(a) of this chapter.

* * * * *

3. Section 271.703 is amended by adding paragraphs (a) and (i) to read as follows:

§ 271.703 Definitions.

For purposes of this subpart:

(a) "Deep-water gas" means natural gas for which a jurisdictional agency determination has become final, pursuant to Parts 274 and 275 that:

(1) The gas is produced from any well the surface drilling of which began on or after May 28, 1980;

(2) The gas is produced from qualified submerged acreage as defined in paragraph (i) of this section; and

(3) For the first sale of which a negotiated contract price is effective.

* * * * *

(i) "Qualified submerged acreage" means any block leased by the Department of the Interior which straddles or is seaward of the 500-foot contour line indicated on maps published and maintained by the National Oceanic and Atmospheric Administration of the Department of Commerce.

PART 273—COLLECTION AUTHORITY: REFUNDS

§ 273.204 [Amended]

4. Section 273.204, paragraph (a) is amended by deleting the word "and" before the number "(ii)", inserting in lieu thereof a comma "," and by adding before the period at the end of paragraph (a) the following: "and (iii) in the case of deep-water gas (as defined in § 271.703(a)) the amount of such excess may be computed, charged, and collected for first sales of such gas delivered on or after May 28, 1980.

PART 274—DETERMINATIONS BY JURISDICTIONAL AGENCIES

5. Section 274.205 is amended by adding a new paragraph (f) to read as follows:

§ 274.205 High-cost gas.

* * * * *

(f) *Deep-water gas.* A person seeking a determination for purposes of Subpart G of Part 271 that natural gas is deep-water gas shall file with the jurisdictional agency an application which contains the following items:

(1) FERC Form No. 121.

(2) Identification of the lease number, the offshore area, and the lease block number.

(3) A copy of the well completion report.

(4) A statement by the applicant, under oath, that:

(i) the surface drilling of the well for which a determination is sought was begun on or after May 28, 1980;

(ii) the gas is produced from qualified submerged acreage;

(iii) the contract for the sale of the subject gas contains a negotiated contract price as defined in § 271.703(e); and

(iv) the applicant has no knowledge of any information not described in the application which is inconsistent with the statements made in accordance with clauses (i) through (iii).

(5) If the jurisdictional agency so requires, certified copies of records relied upon by the applicant including copies of the agency's official files.

¶ 32,075 High-Cost Natural Gas; Production Enhancement Techniques

45 F. R. 51219 (August 1, 1980).

18 CFR Parts 271, 273, and 274

[Docket No. RM 80-50]

High-Cost Natural Gas: Production Enhancement Procedures

Issued: July 25, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby gives notice that it proposes to adopt regulations providing a special incentive maximum lawful price for certain natural gas produced from wells upon which production enhancement work is performed after May 29, 1980. This proposed rule would be applicable only to natural gas that is subject to section 105 of the Natural Gas Policy Act of 1978 (NGPA) on the date of application for determination. The proposal would allow parties to negotiate a price no greater than the maximum lawful price specified in section 109 of the NGPA.

In addition, the Commission consolidates here Docket Nos. RM80-41 and RM80-50 under one docket number, No. RM80-50.

DATE: Written comments by August 25, 1980. Public Hearing to be held August 26, 1980.

ADDRESS: Send written comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Reference Docket No. RM80-50. The public hearing will be held at the same location.

FOR FURTHER INFORMATION CONTACT:

Jeffrey H. Fink, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8111, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8460.

Roger Coven, Office of the General Counsel, Room 4001, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9124.

The Federal Energy Regulatory Commission (Commission) hereby proposes regulations that would establish a special incentive maximum lawful price for certain natural gas produced from wells upon which production enhancement work is performed. These regulations are proposed pursuant to the Commission's authority under section 107 of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. § 3317, to designate certain natural gas as "high-cost natural gas" and to establish incentive prices for such gas. This proposed rule would be applicable only to natural gas that is subject to section 105 of the NGPA on the date of application. The proposal specifies the types of production enhancement procedures that, if applied to a well after May 29, 1980, would result in eligibility for the incentive price. The proposal would allow parties to negotiate a price no greater than the maximum lawful price specified in section 109 of the NGPA. The purpose of the proposed rule is to encourage the production of natural gas that would not be forthcoming under the othewise applicable maximim lawful price.

I. Background

A. Statutory Authority

Under section 107(b) of the NGPA, the Commission has authority to prescribe for any first sale of any high-cost natural gas a maximum lawful price which exceeds the otherwise applicable maximum lawful price to the extent necessary to provide reasonable incentives for the production of such gas. The term "high-cost natural gas" is defined in section 107 of the NGPA to

mean, *inter alia*, "natural gas determined in accordance with section 503 to be . . . produced under such conditions as the Commission determines to present extraordinary risks or costs," section 107(c)(5) of the NGPA. The Commission may provide a maximum lawful price higher than the otherwise applicable maximum lawful price if it determines that the availability of the higher price is required to encourage production of gas which presents extraordinary risks or costs.

The Conference Report [1] suggests examples of natural gas which the Commission might determine are produced under conditions of extraordinary risk or cost: gas from acreage submerged in more than 500 feet of water; tight formation gas; and gas from hydropressured brine. Such sources of natural gas are high-cost gases because of the nature of the geological formation and surrounding geographical conditions from which they are produced. Such formations present especially difficult drilling problems.

The Conference Report continues:

> This authority is intended by the conferees to be exercised in advance of drilling activity, in order to create price incentives. * * *
>
> For example, some new wells will produce from depths close to 15,000 feet and some reentries will produce from depths below 15,000 feet, both possibly involving costs greater than normal, but neither qualifying as high cost gas under sec. 107(c). The Commission may determine that such wells should receive special price treatment under this section. The Commission could also determine that stripper natural gas wells with more than *de minimis* associated oil production qualify for treatment under this section.

It is apparent that the objective behind section 107 is to create an incentive ceiling price for gas supplies that the Congress or the Commission has determined will not be produced under other available maximum lawful prices because of their special expense. In the case of gas produced as a result of production enhancement work, the incentive ceiling price will be allowed on the basis of the risky or costly production techniques that must be applied. The cost of enhancement techniques such as reentry, deeper drilling, and new perforation, when considered against the size of the remaining reserves and the otherwise applicable price, is often prohibitive.[2]

B. Notice of Inquiry

The Commission issued on June 13, 1979, a "Notice of Inquiry Regarding the Implementation of Section 107 (b) and (c) of the Natural Gas Policy Act of 1978." [3] This notice initiated the Commission's efforts to identify categories of high-cost natural gas and correlative incentive prices by seeking general suggestions from the public.

Several responses to that notice of inquiry are relevant to this rulemaking. Some comments remarked that certain reentries and redrillings of old wells involve substantial costs, but that natural gas which might be produced from such old wells must be sold under the NGPA at prices that are often inadequate to compensate for such drilling costs. According to these comments, reentries present high risks to the producer because they involve drilling activity for which ultimate costs cannot be determined until the drilling has terminated. The commenters made the point that without a special incentive price producers will tend to drill new wells rather than reenter old wells, and thereby will fail to conserve drilling resources and to reduce damage

[1] Joint Explanatory Statement of the Committee on Conference, H.R. Rep. No. 95-1752, 95th Cong., 2nd Sess. (1978).

[2] Inclusion of stripper natural gas signifies Congressional willingness to define high-cost natural gas on the basis of low production and the need to encourage enhancement of such production.

[3] Docket No. RM 79-44.

to the environment caused by further drilling.[4]

C. Sun Petition

Late in February of 1980, Sun Gas Company ("Sun Gas") petitioned this Commission for a rulemaking.[5] Docket as No. RM80-41, this petition urged the Commission to classify natural gas produced as a result of "supply enhancement procedures" as high-cost natural gas pursuant to section 107(c)(5) of the NGPA and to prescribe a special incentive price for such gas.[6] By "supply enhancement procedures," Sun Gas included "procedures designated to provide additional supplies, enhance production, or maximize ultimate recovery with respect to gas reserves."[7]

Sun Gas pointed out that current regulations do not allow sufficient flexibility to contracting parties to amend, to modify, or to renegotiate contracts in order to provide for supply enhancement work.[8] Although Commission approval of some contractual arrangements is possible through special relief procedures, Sun Gas described these as inappropriate and too cumbersome.

Further, Sun Gas argued that Congress did not intend to inhibit production of natural gas by preventing contract renegotiation. Sun Gas contends that Congress intended section 107(c)(5) to allow renegotiation of contracts to provide special incentive price treatment for certain production risks.

Procedures such as acidizing, fracturing, and workovers have "extraordinary" risks associated with them "Even if a procedure is designed with the best available technology and is operationally successful when performed, it may not stimulate the production or add the reserve volumes necessary to recover the cost of the work which has been done."[9]

Supply enhancement procedures often become necessary in order to maintain or to increase the production from a depleting well or a well in which production has become marginal. There are many instances in which some form of fracturing is a prerequisite to production but that will not be performed absent an appropriate incentive price. Certain producers who have older, fixed rate intrastate contracts are precluded from modifying

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[4] Comments of Sun Gas Company, filed July 16, 1979 at 4–7, 11; Damon Oil Co., filed July 16, 1979; State of Ohio Department of Natural Resources, filed September 25, 1979 and November 27, 1979 (Ohio suggested allowing an incentive ceiling price at least equal to the section 103 maximum lawful price); Moram Energy Co., filed September 25, 1979; Guernsey Petroleum Corp., filed September 25, 1979; Jerry C. Olds, filed September 25, 1979; Monroe and Keusink, Inc., filed September 26, 1979; and Phillips Products Co., filed September 27, 1979.

[5] Petition of Sun Gas Co. for Rulemaking, In the Matter of Determining Whether Natural Gas Production Achieved as a Result of Supply Enhancement Procedures Should Be Classified as High-Cost Natural Gas Under Section 107(c)(5) of the NGPA, filed February 27, 1980. (Hereinafter "Sun Petition").

[6] *See generally* section 501 of the NGPA relating to the Commission's rulemaking authority.

The incentive price would be applicable by virtue of section 101(b)(5) of the NGPA: "If any natural gas qualifies under more than one provision of [title I of the NGPA] providing for any maximum lawful price . . . with respect to any first sale of natural gas, the provision which would result in the highest price shall be applicable."

[7] Sun Petition at 2.

[8] "[U]nder Section 105 of the Natural Gas Policy Act of 1978, first sellers of natural gas under existing contracts dedicated in intrastate commerce are entitled to collect no more than the lower of the contract price or the section 102 price. Under contracts having no escalation or price redetermination or price renegotiation provision ("fixed price contracts"), there is no mechanism to allow negotiation and collection of a higher rate (not to exceed the section 102 price) prior to the expiration of the existing intrastate contract and the negotiation of a rollover contract where such an increase is dictated by increased expenses incurred in keeping a well or wells producing.

Delhi Gas Pipeline Co., Memorandum in Support of Petition for Rulemaking of Sun Gas Co., filed April 24, 1980 at 6–7. (Hereinafter "Delhi Memo")

[9] Sun Petition at 4. "Failure in this sense means that the procedure, when applied to the particular well will not have the anticipated effect of stimulating production sufficiently to add reserves necessary to recover the costs." Delhi Memo at 3–4. Delhi suggests, as an example of the above, hydraulic fracturing, which is associated with a high risk of casing cement failure.

the price term of their contract in order to cover this additional cost.[10]

II. Summary of Proposed Rule [11]

A. Applicability

The rule proposed in this notice would establish an incentive price, under the authority of sections 107(b) and 107(c)(5) of the NGPA, for "qualified production enhancement gas." Subject to additional restrictions discussed below, the proposed rule would allow the purchaser and the seller to negotiate a price no more than the maximum lawful price permitted under section 109. This incentive price would be available for gas that is subject to section 105 of the NGPA on the date of application and that is produced from a well upon which certain production enhancement work is performed on or after May 29, 1980.

B. Maximum Lawful Price

The maximum lawful price proposed under this rule is the lesser of the section 109 price or the negotiated contract price. A negotiated contract price is required by § 271.703(j)(2) of the proposed rule to be in effect on the date of application and must remain in effect. Any modification of the negotiated contract price requires a new application and new jurisdictional agency determination. "Negotiated contract price" is defined in the existing regulations as "any price established by a contract which either specifically references the incentive pricing authority of the Commission under

[10] In addition to those listed above, expressions of support for the Sun Petition have been received in Docket No. RM80-41 from: Jim Mattox, House of Representatives (Texas), filed April 23, 1980 ("The establishment of a new 'high cost' supply enhancement category under Section 107 of the [NGPA] would allow purchasers and producers to determine, subject to an appropriate ceiling, what price is reasonable for the additional gas expected as a result of specific projects."); Amoco Production Co. (co-signed by attorneys representing at least nine other companies), filed April 30, 1980; Friends of the Earth, filed March 19, 1980; Mustang Fuel Corp., an intrastate pipeline company in Oklahoma, filed May 7, 1980 ("[R]ulemaking which Sun requests would give producers and pipe line purchasers the necessary flexibility to reach mutual agreements on prices for additional gas producers by supply enhancement projects."); Chevron U.S.A Inc., filed May 6, 1980; Amerada Hess Corp., filed May 6, 1980; Energy Reserves Group, Inc., Wichita, Kansas, filed May 5, 1980; the Environmental Policy Center, filed May 9, 1980; Independent Petroleum Assoc. of America, filed May 29, 1980; Oklahoma Natural Gas Company, filed May 28, 1980; and letter from eight senators, dated March 19, 1980 (in support of the type of rulemaking recommended by the petition). To date, no comments opposing the rulemaking have been filed. Pennzoil Co. and Pennzoil Producing Co., as producers of natural gas by supply enhancement procedures, identified their interest in this proceeding and moved for leave to intervene.

[11] It should be noted that the Commission directed the Staff to place the draft approved by the Commission, with a few minor changes, in the public file and to discuss the draft in informal conferences with state jurisdictional agencies and with interested members of the public. Two drafts were thereafter placed in the public file in Docket No. RM80-50: the draft approved in principle on May 29, 1980 and a subsequent draft, dated June 4, 1980, which included minor changes as instructed by the Commission. On June 12, 1980, the Secretary of the Commission issued a Notice of Availability of the Staff draft of the proposed rule in Docket No. RM80-50 and of informal conferences. The informal conferences were announced as an opportunity for interested members of the public to meet with the Staff to discuss the Staff draft of the proposed rule prior to issuance in a Notice of Proposed Rulemaking. The Staff received informal comments on the draft from various state agency representatives and interested members of the public. Members of the public who participated included representatives of Sun Gas Company, Independent Petroleum Association of New Mexico, Mitchell Energy Corporation, Texas Independent Producers and Royalty Owners Association, Natural Resources Corporation, Maguire Oil Company, Loudon Properties of Pennsylvania, and Tenneco. Descriptions of these informal conferences have been placed in the public file.

Upon recognition that Docket Nos. RM80-41 and RM80-50 are addressed to the same goal, the Commission consolidates these two dockets in this Notice under the single docket number No. RM-80-50.

section 107 of the NGPA or contains a fixed rate or a fixed escalator clause."[12]

This requirement is intended to insure that the price for qualified production enhancement gas is set by agreement of all the contract parties.[13] It also will allow some projects to qualify that would be precluded by the cost cap[14] if the maximum lawful price were to be set simply as the section 109 ceiling price. Parties to the contract generally would have to amend their contracts before filing an application with the jurisdictional agency. In addition, the filing requirements state that the portion of the gas sales contract which authorizes collection of the maximum lawful price established in § 271.702(c)(1) must be included in the application. The contract language which must be included in the application will generally be an amendment which has been executed in contemplation of a determination of eligibility under this proposed rule.

An incentive ceiling price not more than the section 109 maximum lawful price is proposed because this ceiling, easily ascertainable and applicable to all eligible projects, is the most administratively convenient to apply and to monitor for compliance. Further, the section 109 ceiling price appears sufficiently high to the Commission to encourage a very large proportion of possible production enhancement projects.

Several commenters suggested that the Commission establish a maximum lawful price greater than the section 109 price. Such suggestions included the section 102 and section 103 ceiling prices. The Commission specifically requests comment on a reasonable incentive price appropriate to the type of high-cost natural gas which is the subject of this proposed rule. In addition, the Commission would find useful any information on the nature and percentage of production enhancement projects which would require a price in excess of the section 109 price as a reasonable incentive to performance, and any projections of additional production that would result if a higher maximum lawful price were established.

The Commission does not believe that Congress intended it to deregulate natural gas subject to section 105 that, but for the proposed rule, would not be sold for a price in excess of $1.00 on December 31, 1984. Therefore, under § 271.702(c)(3) of the proposed rule, the increase in the price paid for the natural gas by virtue of this rule will not result in the elimination of price controls under section 121(a)(3) of the NGPA. Elimination of price controls under that section will occur only if, and when, such elimination would have occurred under the price that would have been applicable but for this rule. The Commission invites comment on this provision and suggestions regarding alternative treatment.

C. Timing

The proposed rule is designed to allow a seller of natural gas to obtain a final determination of eligibility before commencing production enhancement work. The Commission believes that this procedure is necessary to provide a producer with certainty that gas from the subject well will qualify for the incentive price before the producer expends what in many cases will be a considerable investment. On the other hand, the Commission does not wish to promote delay in the performance of such projects. Accordingly, any production enhancement work commenced on or after May 29, 1980,[15]

[12] 18 CFR § 271.703(e). The precise wording of this definition may change when the Commission issues a final rule relating to high-cost natural gas produced from tight formations in Docket No. RM79-76.

[13] It is noteworthy that purchasers, such as Delhi and Mustang Fuel Corp., *see* notes 8 and 12 *supra*, support the establishment of this higher, incentive ceiling price. Delhi asked, however, that the proposed rule permit "bilateral amendments" of the contracts. Delhi Memo at 8-10.

[14] *See* "*Cap on Unit Cost of Incremental Production*" *infra*.

[15] May 29, 1980 is the date that the Commission approved in principle the issuance of this Notice of Proposed Rulemaking.

which meets the qualifications of the rule finally adopted by the Commission will not be excluded from eligibility for the incentive price.

Although the seller may receive a final determination of eligibility before the production enhancement work is commenced, the maximum lawful price established by this proposed rule could not be charged or collected until the production enhancement work is fully completed. If the work is not completed on the date of filing, § 271.702(c)(2) of the proposed rule requires the seller to file an affidavit stating that the production enhancement work upon which the application was based has been completed. This affidavit must be filed with the purchaser, the jurisdictional agency,[16] and the Commission before the seller may charge or collect the newly applicable maximum lawful price.

An application for a jurisdictional agency determination may be based on any work, commenced after May 29, 1980, which otherwise satisfies the requirements of the rule. Collection of payments on an interim basis may begin after the date of application or the date that the production enhancement work is completed, whichever is later.[17] The maximum lawful price provided by this proposed rule may not be collected for deliveries of gas produced from a well before the production enhancement work is fully completed. The Commission requests comment on this affidavit requirement or any other method of insuring that the maximum lawful price is not collected prior to completion of the production enhancement work.

This notice also proposes an amendment to § 273.204(a)(1) of the Commission's regulations governing retroactive collections after a final determination of eligibility. The proposed amendment would allow retroactive collections for first sales of natural gas delivered on or after the date production enhancement work was fully completed. As stated above, collections of the maximum lawful price prescribed in § 271.702(c)(1) will not be allowed for first sales of natural gas delivered before production enhancement work is fully completed. If the work was completed before the date of application, but was commenced on or after May 29, 1980, then collection for deliveries between the dates of completion of work and of filing may be collected retroactively after a determination of eligibility becomes final.

D. Qualified Production Enhancement Gas

The definition of qualified production enhancement gas proposed in § 271.703(j) involves five qualifications. First, the gas must be produced from a well upon which production enhancement work was or will be commenced on or after May 29, 1980. Second, a negotiated contract price must be in effect for the sale of the gas at the time of application and must remain in effect. Third, the gas must be otherwise subject to section 105 of the NPGA at the time of application. Fourth, the special price must be necessary as an incentive for the production of the gas. Finally the incentive price may not result in excessive incremental revenues. This final qualification imposes a cap on the unit cost of the incremental production.

1. *Production Enhancement Work.* Production enhancement work, as defined in § 271.703(k) of the proposed rule, is any work described in one or more of five defined categories. The first category is reentry into a well which has been plugged and abandoned. If a well has been drilled in the past, the drilling equipment has been removed, and the well has been plugged and abandoned, the process of reentering that well to prepare it for production would qualify as production enhancement work. It

[16] Representatives of various jurisdictional agencies supported the suggestion that the affidavit be filed with them also.

[17] *See* 18 C.F.R. §§ 273.101–273.302 (rules governing interim collections and refund obligations).

does not matter whether the well ever has produced gas in the past.

The second category is reentry into a well for the purpose of deeper drilling, or sidetracking, to a new completion location. Under this category, the well need not have been plugged and abandoned.

The third category is recompletion by reperforation of a zone from which natural gas has been produced or by perforation of a new zone. If a well had been drilled originally through a reservoir and completed in a deeper formation, the process of recompleting the well to produce the gas from the upper reservoir would qualify as production enhancement work.

The fourth category is the repair or replacement of faulty or damaged casing, tubing or related downhole equipment.

The final category is fracturing, acidizing or the installation of compression equipment. The Commission recognizes that these types of production enhancement projects often affect more than one well. For example, the process of installing compression equipment upon several wells would constitute production enhancement work with respect to each well affected.

The Commission invites comment on the relative costs and merits of, and the current practices regarding, leasing and buying of compression equipment. In addition, comment is requested regarding the costs and risks of upgrading compression equipment. Much of production enhancement compression might be defined as "production-related" costs under Subpart K of Part 271 of the Commission regulations regarding the NGPA. The regulations covering such allowances will be issued shortly in the rehearing of Order No. 68, Docket No. RM80-14 (January 24, 1980) (45 FR 5678) and in Docket No. RM80-47 (amendments to be made to interim regulations). If cost allowances are permitted for such compression under Subpart K, treatment will not be provided under this proposed rule. Comment is invited on the appropriate treatment of compression of this type.

Although application for determination is to be made on a well-by-well basis, this in no way precludes work that is performed on a field-wide basis.

2. *Other Types of Production Enhancement Work.* During the informal conferences, various interested persons suggested other categories of production enhancement work to be included in § 271.703(k). Such other categories include the cycling of natural gas, nitrogen injection techniques, procedures to control sand or water production or disposal problems, and the installation of artificial lifts such as down-hole pumps. Comment on the costs, risks and possible inclusion of these techniques is requested.

Several commenters also suggested that § 271.703(k) should permit jurisdictional agencies to approve projects involving work not specifically listed in that section. The Commission wishes to avoid the complexities attendant in defining production enhancement work on a case-by-case basis but requests further comment on this suggestion. Suggestions regarding guidelines for the exercise of jurisdictional agency discretion, for example, minimum investment thresholds,[18] would be helpful. Futher, the Commission wishes to consider whether jurisdictional agencies are willing, and have the resources necessary, to make such determinations.

The Commission contemplates that the defined categories of production enhancement work could be expanded

[18] Northwest Resources suggested that special incentive price treatment should be limited to producers who incur a level of expense above a specified investment threshold for enhanced recovery of gas from an existing, producing well. Northwest proposed the requirements that the well must be producing for at least one year prior to recovery enhancement and that the treatment must cost at least $100,000 in total or $1.00 for every Mcf of natural gas produced daily from the well before it was treated. Northwest suggested an incentive ceiling price equal to the section 102 maximum lawful price. Comments of Northwest Resources, October 3, 1979.

by Commission amendment should additional technologies be identified. Comment is specifically requested on all of the suggestions discussed above and on any other types of projects which commenters believe should be included.

3. *Eligible Categories of Natural Gas.* Several comments recommended that gas subject to section 104 (natural gas dedicated to interstate commerce) and section 106 (natural gas sold under rollover contracts) also should qualify for an incentive price under the proposed rule. These parties indicated that the special relief procedures (which apply, or will apply, to gas subject to sections 104, 106 and 109 of the NGPA) will not provide a reasonable incentive for production enhancement projects because of the expense and case-by-case method of application.[19] Although the Commission believes that the need for this proposed rule is most urgent with respect to gas which is subject only to section 105 on the date of application, the Commission specifically requests comment on whether the rule should be broadened to include other categories of natural gas. Discussion by commenters should address those considerations associated with gas that is subject to sections 104 and 106, but not section 105. For instance, such gas may be purchased by interstate pipelines. Special relief is available regarding such gas. In addition, Congress may have expressed an intent to limit the price of "behind-the-pipe gas" that is subject to section 104 to rates previously set by the Federal Power Commission, regardless of the subsequent cost of producing such gas, *see* section 102(c)(1)(C) of the NGPA.

4. *The Reasonable Incentive Requirement.* The fourth component of the proposed definition of qualified production enhancement gas involves the requirement that the special price be necessary as a reasonable incentive. The Commission is authorized under section 107(b) of the NGPA to establish a maximum lawful price applicable to the first sale of high-cost natural gas only "to the extent that such special price is necessary to provide reasonable incentives for the production of such high-cost natural gas." This statutory standard is implemented through three separate requirements.

First, the seller must file an oath statement, required by § 274.205(g)(7), that the price prescribed in § 271.702(c)(1) is necessary as a reasonable incentive and that the production enhancement work would not be performed but for the availability of such price. Several comments were made in the informal conferences to the effect that producers often will find it difficult to swear that *no* work would have been done. Lease requirements and the exigencies of keeping the buyer/seller relationship intact often will act as an incentive to performance of enhancement work of some degree.

Under the proposed rule, the producer need not swear that no work would have been done, but must swear that this work or work of similar type and expense would not have been done absent the incentive price. Of course, as will be discussed, the jurisdictional agencies can examine this oath and the surrounding circumstances.

Second, the purchaser must file a similar oath statement made by the seller, required by § 274.205(g)(8), based on the purchaser's best knowledge or belief. The Commission believes that this oath is useful to evidence compliance with the incentive requirements of section 107 of the NGPA. It simply reflects the decision made by the purchaser when he negotiates to purchase the gas at the incentive price.[20]

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[19] *See* Notice of Proposed Rulemaking, Procedures Governing Applications for Special Relief Under Sections 104, 106, and 109 of the Natural Gas Policy Act of 1978, Docket No. RM79-67 (May 9, 1980). Special relief is not available to sales of natural gas that are subject to section 105.

[20] Comments were made in the informal conferences both in favor and against this purchaser oath. One commenter stated that most contracts give the purchaser the right to examine the producer's reserves data.

Finally, under § 271.703(j)(4) the jurisdictional agency must find a reasonable basis to conclude that the assertions contained in these two oath statements are reasonable. This final requirement gives the jurisdictional agency discretion to make a negative finding on an application if the jurisdictional agency believes that the special price is not necessary as a reasonable incentive for the increase in production of gas. A jurisdictional agency could find, for example, that a project which would not involve significant expense would be done without the availability of the special incentive price.

5. *Cap on Unit Cost of Incremental Production.* Finally, qualified production enhancement gas is defined as natural gas that will result in a projected increase in revenue, which when divided by the projected increase in units of production (MMBtu's), does not exceed the imported oil equivalent price for the month the application is filed. In other words, if the total projected increase in revenue is attributed only to the projected increase in units of production, the revenue from each such unit of production cannot exceed the equivalent price for imported crude oil. This requirement is intended to insure that the actual cost to the purchaser, and thus to the consumer, of the increase in gas supply does not exceed the cost of alternative fuels.

The calculations which form the basis of the this cost cap are based on estimates filed with the application. The applicant must file two estimates with the jurisdictional agency.[21] First, the applicant must estimate the total units of production (MMBtu's) which would be produced from the well over a five year period from the month of application if the production enhancement work that is the subject of the application is not or was not performed. In some cases, for example, where a well which has been plugged and abandoned, this estimate will be zero. The applicant also must estimate the total units of production (MMBtu's) which would be produced from the well over the same five year period if the production enhancement work had been completed by the date of application. Naturally, these estimates may be made before any work is commenced on the well. The estimates must be as accurate as is reasonably possible at the time of application. Nevertheless, this calculation is not a pricing mechanism, but a test of reasonableness regarding the claim of an incentive. The Commission is aware that some projects may fall short of estimated production or may fail completely to enhance production.

Once these estimates are made, "projected increase in units of production" can be calculated simply by subtracting the first estimate from the second. To calculate "projected increase in revenue," the applicant must multiply the first estimate (units of production if no work performed) by the maximum lawful price otherwise applicable to first sales of gas from the well on the date of application. The applicant must then multiply the second estimate (units of production if work completed on date of application) by the negotiated contract price (if such price is less than the section 109 price and if such price does not increase, for example, by any escalator) or by the section 109 price in any other case. Projected increase in revenue is the second product less the first product.

Finally, the applicant must divide projected increase in revenue by projected increase in units of production. The resulting figure, expressed in dollars per MMBtu, may not exceed the "imported oil equivalent price" for the month the application is filed. Imported oil equivalent price is defined in § 271.703(n) as the national

[21] These estimates are required to be made for a projected five year period. Comment is invited on the usefulness of this time period, as compared with a shorter or longer period. In addition, the Commission would find helpful data regarding the average remaining producible life of wells which would be affected by this rule.

average refinery acquisition cost of imported crude oil, calculated and published pursuant to 10 CFR § 211.67(i) by the Department of Energy in the Monthly Entitlements Notice, divided by a Btu conversion factor of 5.8.

It is important to note that a project which is disqualified by this cost cap when the section 109 price is used to calculate projected increase in revenue may still qualify for an incentive price under this proposed rule. An applicant may bring a marginal project into the scope of the rule by negotiating a price below the section 109 price.

The Commission realizes that the projected increase in revenue must be claculated based on a series of approximations. Not only is the total production over the five year period estimated, but the ceiling prices applied are those for the month of application rather than those which would apply for each month over the five year period.[22] Nevertheless, the Commission believes that the calculations required will be sufficiently accurate to suit the purpose for which they are intended.

Most of these requirements for qualification as production enhancement gas are to test the legitimacy of any project and to determine whether the new maximum lawful price is necessary as a reasonable incentive. The Commission welcomes comment on these safeguards in the proposed rule or suggestions regarding any other safeguards.[23]

III. Public Procedure

Any interested persons may submit data, views or arguments regarding this proposed rulemaking. An original and 14 copies of such comments should be filed by August 25, 1980, with the Secretary, Federal Energy Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Each submission should include the name and address of the person submitting the comments, should refer to Docket No. RM80–50, and should include the reasons for any recommendations. Comments should state the name, title, mailing address, and telephone number of one person to whom the communications concerning the amendment may be addressed. Written comments will be placed in the Commission's public file and will be available for public inspection during regular business hours at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

A public hearing concerning this proposal will be held at the offices of the Commission at 825 North Capitol Street, N.E. Washington, D.C. on August 26, 1980, beginning at 10:00 a.m., and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m. on August 21, 1980.

Requests to participate in the hearing should reference Docket No. RM80–50, and should include a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted with the request to participate to the Secretary of the Commission. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

An additional public hearing may be held in an appropriate city outside of

[22] Naturally, the true ceiling prices for each month could not be calculated until the inflation factor is established for every succeeding month.

[23] Several comments were made in the informal conferences asserting, for instance, that the relative bargaining strength of the purchasing pipeline will maintain low incentive prices.

Washington, D.C. if sufficient interest in such a hearing is expressed.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. The presentation will be made before a panel whose members will be designated by the Chairman of the Commission. The panel may question persons presenting statements and any interested persons may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rule will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Department of Energy Organization Act, 42 U.S.C. §§ 7107–7352; E.O. 12009, 42 *Fed. Reg.* 46267; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3422.)

In consideration of the foregoing, the Commission proposes to amend Subpart G of Part 271, Subpart B of Part 273, and Subpart B of Part 274, Subchapter H, Chapter I, Title 18 of the Code of Federal Regulations set forth below. In addition, Docket Nos. RM80–41 and RM80–50 are hereby consolidated under one docket heading, Docket No. RM80–50.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 271—CEILING PRICES

1. Section 271.701 is revised to read as follows:

§ 271.701 Applicability.

This subpart implements section 107 of the NGPA and applies to the first sale of natural gas which a jurisdictional agency determines, in accordance with Parts 274 and 275, is one of the following:

(a) New tight formation gas.

(b) [Reserved].

(c) Qualified production enhancement gas.

2. Section 271.702 is amended by adding a new paragraph (c) to read as follows:

§ 271.702 Maximum lawful prices.

* * * * *

(c) *Qualified production enhancement gas.* (1) *Maximum lawful price.* The maximum lawful price, per MMBtu, for the first sale of qualified production enhancement gas shall be the lesser of:

(i) the negotiated contract price; or

(ii) the maximum lawful price specified for Subpart I of Part 271 in Table I of § 271.101(a).

(2) *Requirement of completed production enhancement work.* If the production enhancement work has not been completed on or before the date that the application is filed, the maximum lawful price provided in paragraph (c)(1) of this section shall not apply until the seller has filed an affidavit with the purchaser, the jurisdictional agency, and the Commission, stating that the production enhancement work, upon which the application for determination of eligibility was based, has been completed.

(3) *Elimination of price controls.* For purposes of determining the price paid under section 121(a)(3) of the NGPA, any amount paid solely by virtue of a maximum lawful price allowed by this section shall be disregarded.

(4) *Cross reference.* For the special rule on retroactive collections for qualified production enhancement gas, see § 273.204(a) of this chapter.

3. Section 271.703 is amended by adding new paragraphs (j), (k), (l), (m), and (n) to read as follows:

§ 271.703 Definitions.

* * * * *

(j) "Qualified production enhancement gas" means natural gas:

(1) That is produced from a well upon which production enhancement work

was commenced, or will be commenced, on or after May 29, 1980;

(2) For which a negotiated contract price is effective including the time at which the application is filed;

(3) For which the maximum lawful price at the time of application is prescribed by Subpart E of Part 271;

(4) For the production of which the seller asserts, the purchaser concurs, and there is a reasonable basis, grounded in part on the amount of the investment, to conclude that:

(i) the price prescribed in § 271.702(c)(1) is necessary as a reasonable incentive; and

(ii) but for the availability of the price prescribed in § 271.702(c)(1), the production enhancement work would not have been performed or will not be performed; and

(5) As calculated by the seller (for a five year period beginning from the month of application, based on estimates filed pursuant to § 274.205(g)(4)) will result in a projected increase in revenue which, when divided by the projected increase in units of production, does not exceed the imported oil equivalent price for the month that the application is filed.

(k) "Production enhancement work" means any work that is performed for the purpose of one or more of the following:

(1) Reentry into a well which has been plugged and abandoned;

(2) Reentry into a well for the purpose of deeper drilling, or sidetracking, to a new completion location;

(3) Recompletion by reperforation of a zone from which natural gas has been produced or by perforation of a new zone;

(4) Repair or replacement of faulty or damaged casing, tubing, or related downhole equipment; or

(5) Fracturing, acidizing, or the installation of compression equipment.

(l) "Projected increase in revenue" means:

(1) the product (i) the estimated units of production (MMBtu's) which would be produced from the well over the five year period specified in § 271.703(j)(5) if production enhancement work had been completed on the day that the application is filed, times (ii) the negotiated contract price specified in § 271.702(c)(1)(i) (if such price is a fixed price which is less than the price provided in § 271.702(c)(1)(ii)) or the price specified in § 271.702(c)(1)(ii) in any other case, for the month that the application is filed, less

(2) the product of (i) the estimated units of production (MMBtu's) which would be produced from the well over the same five year period if the production enhancement work is not performed or had not been performed, times (ii) the maximum lawful price otherwise applicable to natural gas from the well as of the date the application is filed.

(m) "Projected increase in units of production" means

(1) the estimated units of production (MMBtu's) which would be produced from the well over the five year period specified in § 271.703(j)(5) if the production enhancement work had been completed on the day that the application is filed, less

(2) the estimated units of production (MMBtu's) which would be produced from the well over the same five year period if the production enhancement work is not performed or had not been performed.

(n) "Imported oil equivalent price" means the national average refinery acquisition cost of imported crude oil, calculated and published pursuant to 10 CFR 211.67(i) by the Department of Energy in the Monthly Entitlements Notice, divided by 5.8.

PART 273—COLLECTION AUTHORITY; REFUNDS

§ 273.204 [Amended]

4. Section 273.204 is amended in paragraph (a)(1) by deleting the word "and" at the end of clause (i), by inserting at the end of clause (ii) the word "and", and by adding the following clause: "(iii) in the case of

qualified production enhancement gas (as defined in § 271.703(j)), of the production enhancement work has been completed before the date of application, the amount of such excess may be computed, charged, and collected for first sales of such natural gas delivered on or after the date that the production enhancement work was completed;"

PART 274—DETERMINATIONS BY JURISDICTIONAL AGENCIES

5. Section 274.205 is amended by adding a new paragraph (g) to read as follows:

§ 274.205 High-cost natural gas.

* * * * *

(g) *Qualified production enhancement gas.* A person seeking a determination for purposes of Subpart G of Part 271 that natural gas is qualified production enhancement gas shall file with the jurisdictional agency an application which contains the following items:

(1) FERC Form No. 121.

(2) A detailed description of the production enhancement work which has been performed on the well, including the dates such work was commenced and completed, or which will be performed on the well;

(3) Copies of invoices and bills necessary to verify the cost of performing the production enhancement work described in § 271.703(k) or, if the work has not yet been completed, estimates of such cost in lieu thereof;

(4) An estimate, for the five-year period beginning from the month in which the application is filed, of the units of production (MMBtu's) that:

(i) would be produced from the well if the production enhancement work had been completed on the day that the application is filed; and

(ii) would be produced from the well if the production enhancement work is not performed or had not been performed;

(5) Calculations, based on the estimates required by paragraph (g)(4) of this section and made in accordance with § 271.703(j)(5), which demonstrate that the projected increase in revenue from the well divided by the projected increase in units of production does not exceed the imported oil equivalent price, as defined in § 271.703(n), for the month that the application is filed;

(6) A copy of that portion of the sales contract that authorizes collection of the maximum lawful price specified in § 271.702(c)(1);

(7) A statement by the applicant, under oath, that:

(i) the price prescribed in § 271.702(2)(1) is necessary to provide a reasonable incentive for the performance of the production enhancement work;

(ii) but for the availability of the maximum lawful price prescribed in § 271.702(c)(1), the production enhancement work would not have been performed or will not be performed;

(iii) the production enhancement work was not commenced before May 29, 1980;

(iv) to the best of the applicant's knowledge and belief, the estimates required by paragraph (g)(4) of this section are reasonable; and

(v) the applicant has no knowledge of any other information not described in the application which is inconsistent with these conclusions and estimates;

(8) A statement by the purchaser, under oath, to the best of the purchaser's knowledge or belief, that:

(i) the price prescribed in § 271.702(c)(1) is necessary to provide a reasonable incentive for the performance of the production enhancement work; and

(ii) but for the availability of the price prescribed in § 271.702(c)(1), the production enhancement work would not have been performed or will not be performed; and

(9) If the jurisdictional agency so requires, certified copies of records upon which the applicant relied, including copies of the jurisdictional agency's official files.

¶ 32,076 Proposed Revision to Annual Report of Gas Supply for Certain Natural Gas Pipelines: Form No. 15

45 F. R. 54082 (August 14, 1980).

18 CFR Part 260

[Docket No. RM80-69]

Proposed Revision To Annual Report of Gas Supply for Certain Natural Gas Pipelines: Form No. 15

Issued August 7, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: By this Notice, the Federal Energy Regulatory Commission proposes to amend Form No. 15 (Interstate Pipelines' Annual Report of Gas Supply). The proposed amendments include changing the number of schedules contained in the form, the format of those schedules and statements in the form, and the instructions for completion of the form. As a result, the reporting burdens will be reduced by approximately one third.

The proposed changes are a product of the Commission's ongoing effort to eliminate unnecessary reporting burdens and to update its forms.

DATE: Comments are due September 26, 1980.

ADDRESS: Comments to this Notice should be addressed to the Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM80-69.

FOR FURTHER INFORMATION CONTACT: Wayne Thompson, Chief, Gas Supply Branch, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 4402-B, Washington, D.C. 20426 (202) 357-9077.

SUPPLEMENTARY INFORMATION:

The Federal Energy Regulatory Commission (Commission) is engaged in an ongoing effort to eliminate unnecessary reporting burdens. This rulemaking to amend Form No. 15, Annual Report of Gas Supply for Certain Natural Gas Pipelines, is part of that effort and reflects an evaluation of data needed by the Commission to carry out its regulatory functions. The proposed amendments to the content, format, and instructions of Form No. 15 should result in a significant reduction in respondent burden and improve the quality of the responses filed under Form No. 15.*

A. Background

Form No. 15 was instituted to obtain an annual report of the total gas supply of each pipeline company under the jurisdiction of the Commission.[1] This gas

* FERC Form No. 15 [Attachment A] is not being printed by the **Federal Register**. Copies are available in the Office of Public Information.

[1] Form No. 15 was initially promulgated in 1964: Order No. 279, Docket No. R-239, 29 FR 4874 (April 7, 1964). It has undergone four revisions since that date: Order No. 337, Docket No R-308, 32 FR 3292 (February 25, 1967), revised the form to allow companies with comparatively small volumes of reserves to file an abbreviated report, and made certain conforming amendments; Order 399, Docket No. R-308, 35 FR 6962 (May 1, 1970), amended the form to require respondents to submit estimates of productive capacity Mcf/d, maximum daily quantity Mcf/d for each source of gas supply and gas reserves by independent producer rate schedules, and made other minor changes; Order No. 476, Docket No R-308, 38 FR 6810 (March 13, 1973), amended the form with reference to the reserves report; and Order No. 548, Docket No. R-308, 41 FR 9868 (March 8, 1976), revised the form to require that respondents disclose gas reserves filings with other Federal agencies.

supply consists of the pipeline company's owned reserves, producer contracts for which the producer has received a certificate to sell the gas to the pipeline,[2] gas purchase contracts with other jurisdictional pipelines,[3] purchases of gas from foreign suppliers, purchases of Liquefied Natural Gas (LNG), Synthetic Natural Gas (SNG),[4] and short-term or other purchases over which the Commission has regulatory authority.

Form No. 15 provides the Commission with information needed to address gas supply issues in certificate applications, to perform depreciation analyses in rate cases and to make determinations concerning new or increased sales, the extension of facilities, or the abandonment of services.

There are at least four problems which have become evident in the use of the current Form No. 15: (1) excessive detail is prescribed for individual reservoirs; (2) definitions and data requests in the form do not conform to changes resulting from passage of the Natural Gas Policy Act (NGPA); (3) definitions are not adequately standardized to permit cross checks with other data; and (4) the format of the computer printout ("hard copy") is designed for computer use, rather than human use.

By this rulemaking, the Commission is proposing certain changes in the form which will address these problems. In addition, the Commission's review of regulatory burdens indicates that the proposed revisions to Form No. 15 will make the form more concise, will better facilitate its use and will reduce respondent burdens.

B. Current Format

Form No. 15 is currently composed of: (1) forty-five pages of filing instructions (pp. 0001–0045); (2) three unnumbered statements—"Disclosure of Other Gas Supply Filings With Federal Agencies" (p. 0046), "Synopsis of Pipeline Company Gas Supply" (p. 0047), and "Gas Procurement Activity Statement" (p. 0048); (3) four schedules designed more for computer use rather than for completion by hand—"Schedule No. I—System Deliverability Summary," "Schedule No. II—Reservoir Data and Dedicated Remaining Recoverable Salable Reserves," "Schedule No. III—Deliverability Estimate for Each Supply Source," and "Schedule No. IV—Committed Reserves and Deliverability Estimates for Other Supply Sources;" and (4) a "Footnote Data" page.

C. Summary of Proposed Changes

1. General

The Commission proposes to revise and clarify Form No. 15 and its instructions, including consolidating and renumbering its schedules and reporting statements. The schedules would also be redesigned to better facilitate completion by hand. As a result of these revisions, the reporting requirement of the respondent pipelines should be reduced by approximately one third.

An "Identification Schedule" (page 1) which includes a certification section would be added to the form, on which the reporting pipeline company would identify itself, state the number of pages submitted for each statement and schedule, and attest to the accuracy of the reported information. "Synopsis of Pipeline Company Gas Supply" (page 0047) would be shortened to "Synopsis of Gas Supply" and renumbered as page 2; "Disclosure of Other Gas Supply Filings With Federal Agencies" (page 0046) would be redesignated as page 3; and the "Gas Procurement Activity Statement" (page 0048) would be identified as page 4. The current "Schedule I—System Deliverability Summary," would remain Schedule I (page 5); the present "Schedule II—

[2] Pursuant to the Natural Gas Policy Act (NGPA), producers are no longer required to obtain certificates in certain instances. (*See* sections 302, 312 and 601, NGPA.)

[3] Pursuant to the NGPA, pipelines are permitted to purchase gas from nonjurisdictional companies. (*See* sections 302, 303 and 311, NGPA.)

[4] Also known as "Substitute" Natural Gas.

Reservoir Data and Dedicated Remaining Recoverable Salable Reserves" and "Schedule III—Deliverability Estimate for Each Supply Source" would be combined into "Schedule II—Reservoir Data, Field Data, Salable Reserve Data and Deliverability Estimate" (page 6); and the current "Schedule IV—Committed Reserves and Deliverability Estimates for Other Supply Sources" would be renumbered as the new Schedule III (page 7). The "Footnote Data" page (page 8) would be revised to include certain classification and footnote codes for reporting the required data.

A requirement to report a "Class Code" on each statement and schedule would be deleted. A space would be provided on each statement and schedule for designating the report as "an original" or "a resubmission." A resubmission would be filed when reportable data have changed from the originally filed form. Only such altered data and data of resubmission would have to be reported. Finally, a separate instruction is included for the attachment of pipeline system maps.[5]

2. Statements

The first substantive statement, "Synopsis of Gas Supply" (new page 2) would be changed as follows: Items 4 through 10 of the old form which pertain to information from the last certificate application would be deleted. For purposes of clarification with reference to gas reserves, two lines are proposed to be added to the statement entitled, "Company Owned Recoverable Gas in Underground Storage," and "Gas Balance Due From Exchange Agreements (Positive or Negative)."

The second statement, "Disclosure of Other Gas Supply Filings With Federal Agencies" (new page 3) would remain essentially the same. The definition of the term "affiliates" would be included for purposes of clarification.

The third statement, "Gas Procurement Activity Statement" (page 4) would be essentially unchanged.

3. Schedules

The following items would be deleted from "Schedule I—System Deliverability Summary" (page 5): "Annual Requirements" [6] (for all years except the current year), "Gas Curtailments" (Line Nos. 03–22); "Firm Gas Sales," "Interruptible Gas Sales," "Other Use Gas," "Reserve Life Index," and "Short Term Contract Volume" (Line No. 25). The item labeled, "Contracted" which is presently reported under "Current Gas Supply" would be retitled "Producer Dedicated" for purposes of clarification.

The new "Schedule II—Reservoir Data, Field Data, Salable Reserve Data, and Deliverability Estimate" (page 6) would be the product of extensive revisions and deletions as a result of the merger of the current Schedules II and III. The schedule would be used only for reservoir and field data—all "Group" data would be required to be reported on the new Schedule III. Elements eliminated from each form would be as follows:

Current Schedule II

Group Code
Line No. 1—FPC Natural Gas Area
Line No. 2—Type calculation
Total Producing Completions
Total Net Completions
Dedicated Percentage of Sellers Reserves
Decline Factor MMCF Per PSI
Cumulative Wet Gas Production at Current Pressure
Current Z Value
Terminal Z Value
Depth Classification
Basic Lithology
Line No. 4—Recovery Factor
Productive Area—Acres
Average Net Thickness—Feet
Reservoir Volume—Acre/Feet
Porosity
Porosity By (How porosity is determined)
Connate Water

[5] Elimination of the requirement to file individual reservoir area outline maps reduces the respondents' map filing burden by over 50 percent.

[6] Estimated total pipeline system annual gas requirements.

Connate Water By (How connate water is determined)
Initial Z Value
Yield Barrels Per MMCf
FVF (Initial Formation Volume Factor)
Mole Percent H_2S
Mole Percent N_2
Mole Percent CO_2

Current Schedule III

Line No. 1—all data elements
Line No. 2—all data elements
Line No. 3—Pc (Shut-in pressure)
Pt (Flowing pressure)
Pf (Formation pressure)
PS (Sandface pressure)
C (Coefficient C in back pressure equation)
n (value of slope n)
Q (rate of flow)
Duration Flow
Wellhead Open Flow
Absolute Open Flow
Daily Productive Capacity—Non-Associated Gas
Daily Productive Capacity—Associated and Solution Gas

Three data elements would be added to the new Schedule II for clarification purposes: "New Reservoirs," "Extensions", and "Revisions (Plus or Minus)."

The new "Schedule III—Committed Reserves and Deliverability Estimates for Other Supply Sources" (page 7) would require the filing of field data by those companies which are not required to file Schedule II,[7] or when there is insufficient data to file Schedule II. In these instances, the field name and code would be substituted for group name and code. The following items would be deleted from Schedule III: "FPC Natural Gas Area" (Line No. 1); "Daily Productive Capacity for Undesignated Gas," "Daily Productive Capacity for Non-Associated Gas," and "Daily Productive Capacity for Associated and Solution Gas" (Line No. 2); and "Gas Volume Not Scheduled" (Line No. 3). A requirement for filing "Type of Gas" is added for clarification. The Commission also proposes an additional line item entitled, "Intrastate or Interstate"[8] in order to identify the type of gas sale. Finally, certain changes are proposed for the current "Committed Reserves" portion of the form in order to better distinguish company owned production and reserves from contracted purchases and reserves. Thus, "Company Owned" is replaced by "Company Owned Remaining Dry Gas;" "Owned and Contracted" is now "Remaining Contracted Gas;" "Gas Purchased and/or Produced" is replaced by "Contracted Gas Purchased" and a new item, "Company Owned Dry Gas Produced" is added.

3. Instructions

The reporting instructions and definitions are proposed to be changed to reflect revisions in and to clarify reporting requirements of Form No. 15. While the schedules will be revised to better facilitate completion by hand, the Commission will retain its preference that respondents file a magnetic tape (computer copy) of the form.[9] In order to ease the data processing burdens for respondent companies, the Commission has requested the Energy Information Administration (EIA) to develop a computer program which would translate the current requirements into the proposed format. As a result, respondents could continue to file magnetic tape copies under the current format without reprogramming their computers.[10] The "hard copy" (computer printout) would, however, still have to be filed in the proposed format. The Commission specifically seeks views on this proposal from the affected respondents.

[7] Companies with gas reserves which are owned and controlled by producers and which amount to less than 50 billion cubic feet of natural gas at the end of any reporting year; or companies which purchase their entire supply of natural gas from other companies subject to Form No. 15 requirements, and/or from foreign suppliers.

[8] *See also* section 311, NGPA.

[9] *See* Attachment A for the revised instructions for magnetic tape filings.

[10] In order for the translation program to be successful, EIA could make no exceptions for magnetic tape filings.

The Commission would also revise certain of the form's definitions to reflect other changes and to correspond to provisions in currently applicable statutes.

The proposed changes should provide the Commission with more meaningful data in a more usable form and should ease respondent burdens substantially. Because of these advantages, it is proposed that the changes described in this Notice should be implemented in time for the report due on or before April 1, 1981.

In addition to the above-described changes to Form No. 15, the Commission proposes to amend those regulations which reference Form No. 15. Section 260.7 would be changed to designate the form as "FERC" Form No. 15. In the prescription, the term "interstate pipeline companies, as defined by the Natural Gas Policy Act," would replace "natural gas company, as defined by the Natural Gas Act." Section 260.7a would be amended to provide for the filing of a statement of gas transported by pipelines for other companies. Other revisions would be made to reflect changes in the effective date and in schedule and statement designations, and to clarify the prescription of the form.

D. Written Comment Procedures

The Commission invites interested persons to submit written data, views and other information concerning the matters set out in this Notice. An original and 14 copies of such comments should be filed with the Commission by September 26, 1980. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should reference Docket No. RM80-69.

All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426 during regular business hours.

(Department of Energy Organization Act, 42 U.S.C. 7101-7352; E.O. 12009, 42 FR 46267; Natural Gas Act, 42 U.S.C. 3301-3432)

In consideration of the foregoing, the Commission proposes to amend Form No. 15 as set forth in Attachment A, and Part 260, Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By direction of the Commission.
Kenneth F. Plumb,
Secretary.

1. Part 260—Statements and Reports (Schedules) is amended in the Table of Contents and in the text by revising §§ 260.7 and 260.7a to read as follows:

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

* * * * *

Sec.
260.7 FERC Form No. 15, Interstate pipelines' annual report of gas supply.
260.7a Annual statement of gas transported by interstate natural gas pipelines for other interstate natural gas pipelines.
* * * * *

§ 260.7 FERC Form No. 15, Interstate pipelines' annual report of gas supply.

(a) *Prescription.* The form of Interstate Pipelines' Annual Report of Gas Supply, designated herein as FERC Form No. 15, is prescribed for the year 1980 and thereafter.

(b) *Filing requirements.* (1) *Who must file.* (i) *Generally.* All interstate pipeline companies, as defined by the Natural Gas Policy Act, section 2(15), shall prepare and file with the Energy Information Administration (EIA) an original and four copies of FERC Form No. 15.

(ii) *Exceptions.* The following interstate pipelines shall prepare and file with EIA an original and four copies of only the Identification Schedule (with Certification) (page 1), the "Synopsis of Gas Supply" (page 2) and Schedule III of

ERC Form No. 15: (A) each interstate
peline with gas reserves that are
vned and controlled by producers and
at amount to less than 50 billion cubic
et of natural gas at the end of any
porting year: or (B) each interstate
peline that purchases its entire supply
natural gas from other interstate
pelines subject to the provisions of
s section, and/or from foreign
ppliers.

(2) *When to file.* Such reports shall be
led on or before April 1 for each
alendar year ending December 31 of
e previous year.

§ 260.7a Annual statement of gas transported by interstate pipelines for other interstate pipelines.

Each interstate pipeline, as defined by the Natural Gas Policy Act, section 2(15), which only transports natural gas for another interstate pipeline shall prepare and file with the Energy Information Administration an original and four copies of a statement which contains the name and address of each interstate pipeline for which it transports the gas. Such statement shall be filed on or before April 1 for each calendar year ending December 31 of the previous year.

¶ 32,077 High-Cost Gas Produced From Tight Formations

45 F. R. 56072 (August 22, 1980).

18 CFR Part 271

[Docket No. RM79-76; Texas—1]

High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final rule designating natural gas produced from tight formations as high-cost gas subject to a higher ceiling price (18 CFR 271.705). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Texas Railroad Commission that Cotton Valley Sand Formation, Cotton Valley Lime Formation, and Bossier Shale Formation be designated as tight formations pursuant to section 271.705.

COMMENT DATE: Comment period expires on September 29, 1980.

ADDRESS: comments to this Notice should be addressed to the Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, and should reference Docket No. RM79-76.

FOR FURTHER INFORMATION CONTACT:

Leslie J. Lawner, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol St. NE., Washington, D.C. 20426, (202) 357-8027.

Teresa Ponder, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol St. NE., Washington, DC 20426, (202) 357-8151.

SUPPLEMENTARY INFORMATION:

Issued: August 15, 1980.

I. Background

On July 11, 1980, the Texas Railroad Commission (Texas) submitted to the Commision a recommendation, in accordance with § 271.705 of the Commission's regulations (18 CFR § 271.705), that the Cotton Valley Sandstone Formation, the Cotton Valley Lime Formation and the Bossier Shale Formation be designated as tight formations in the Commission's regulations. Pursuant to § 271.705(d) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Cotton Valley Sandstone, Cotton Valley Lime and Bossier Shale Formations be designated as tight formations, should be adopted. Texas' recommendations and supporting data are on file with the Commission and are available to the public for inspection.

The recommended formations are found in the northeastern part of the State of Texas, encompassing parts of Railroad Commission Districts 1, 3, 5 and 6. Northern limits of the recommended formations lie immediately south of the Texas-Oklahoma border through Fannin, Lamar, and Red River Counties, and the eastern border extends to the Arkansas and Louisiana borders. The southern boundary is determined by the Angelina-Caldwell flexture from Sabine through San Augustine, Angelina, and Trinity Counties. The western boundary is determined by the Mexia-Talco fault zone through Limestone, Navarro, and Kaufman Counties.

The recommended formations are described by Texas, in pertinent part as follows: The Cotton Valley Sand lies above the Bossier Shale, and the Bossier

Shale lies above the Cotton Valley Lime. These three formations are referred to, collectively, as the Cotton Valley Group. The average depth at which the Cotton Valley Sand can be encountered is approximately 7000' to the north, 8000' to the east, between 10,000' to 11,000' to the south, and 5090' to the west. Thickness of the Cotton Valley Sand reaches a maximum of 1600'. The top of the Bossier Shale is located at approximately 7700' to the north, 10,720' to the east, 12,600' to the south, and 5340' to the west. Formation thickness of the Bossier Shale ranges from 110' to 580'. Within this formation, laminated sand bodies are present which range up to 90' in thickness. The Cotton Valley Lime is encountered at depths of approximately 8000' to the north, 11,400' to the east, 13,200' to the south, and 5500' to the west.

Texas asserts that its recommendations meet all the requirements set forth in § 271.705(b)(1) of the Commission's regulations which must be satisfied in order for a formation to receive a formal designation as a tight formation. Under § 271.705(b)(1), the three requirements which must be met are:

(1) The estimated average *in situ* gas permeability throughout the pay section of the formation is expected to be 0.1 millidarcy or less;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation, is not expected to exceed production levels determined by reference to well depth, as found in the table in § 271.705(b)(1)(ii); and

(3) No well drilled into the formation is expected to produce more than five barrels of crude oil per day.

II. Discussion of the Proposal

In its submission, Texas presents a geographical and geological description of the recommended formations. Calculations were presented, demonstrating that the estimated *in situ* gas permeability throughout the pay section of each recommended formation is expected to be 0.1 millidarcy or less. Texas' filing shows that the stabilized production rates of wells completed for production, without stimulation, are within the limits of the table set forth in § 271.705(b)(1)(ii). It is also asserted by Texas that production history establishes that no well drilled into the Cotton Valley Group is expected to produce more than five barrels of crude oil per day. A list of wells which have produced natural gas from the recommended formations was submitted. Texas stated that existing state and federal regulations will assure that development of the recommended formations will not adversely affect any fresh water aquifers that are or are expected to be used as domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68, it is proposed that the Cotton Valley Sandstone, Cotton Valley Lime and Bossier Shale Formations, as they are described and delineated in Texas's recommendation as filed with the Commission, be designated as tight formations pursuant to § 271.705.

III Public Comment Procedures

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., N.E., Washington, D.C. 20426. Comments should reference Docket No. RM79-76 (Texas-1). All comments and information received by the Commission prior to September 29, 1980 will be considered prior to the issuance of the rule.

Dates and locations of any hearings held on this rulemaking will be announced in the near future.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

In consideration of the foregoing the following amendments to Part 271, Chapter I, Title 18, Code of Federal

Regulations, are proposed, as set forth below.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. The Table of Contents for Subpart G of Part 271 is changed by adding a new § 271.706 to read as follows:

• • • • •

271.706 Designated tight formations.

2. Part 271 is amended by adding a new § 271.706 to read as follows:

§ 271.706 Designated tight formations.

(a) The following formations are designated as tight formations:

(1) *The Cotton Valley Group in Texas.* Cotton Valley Sandstone, Cotton Valley Lime and Bossier Shale Formations, comprising the Cotton Valley Group.

(i) *Delineation of Formations.* The northern boundary of the Cotton Valley Group is the Texas-Oklahoma border extending through Fannin, Lamar and Red River Counties; the eastern boundary is formed by the Texas-Arkansas and Texas-Louisiana borders; the southern boundary is along the Angelina-Caldwell flexture running through Sabine, San Augustine, Angelina and Trinity Counties; the western boundary is set by the Mexia-Talco fault zone through Limestone, Navarro and Kaufman Counties.

(ii) *Depth.* Cotton Valley Sand is encountered at an average depth of approximately 7,000' to the north, 8,000' to the east, between 10,000'and 11,000' to the south, and 5,000' to the west; Bossier Shale is encountered at 7,700' to the north, 10,720' to the east, 12,600' to the south, and 5340' to the west; Cotton Valley Lime is encountered at 8000' to the north, 11,400' to the east, 13,200' to the south, and 5500' to the west.

(2) [Reserved]

(b) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,078 Exemption From All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects With a Proposed Installed Capacity of 5 Megawatts or Less

45 F. R. 58368 (September 3, 1980).

18 CFR Parts 4 and 375

[Docket No. RM80-65]

Exemption From All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects With a Proposed Installed Capacity of 5 Megawatts or Less; Proposed Rulemaking and Public Hearing

Issued: August 28, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking and Public Hearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to adopt a rule that would implement, in part, section 408 of the Energy Security Act of 1980. In section 408, the Congress provided the Commission with discretion to exempt certain small hydroelectric power projects from applicable provisions of the Federal Power Act (Act), either by means of case-by-case determinations or according to classes or categories of such projects. The proposed rule establishes procedures for case-by-case exemptions.

The Commission requests any interested party to comment on the proposed rule or to participate in a public hearing to be held on September 23, 1980. Hearing participants must notify the Secretary by September 19, 1980.

DATES: Written comments by September 29, 1980. Public Hearing at 10:00 a.m. on September 23, 1980.

ADDRESS: Location of Hearing: Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Room to be posted.

FOR FURTHER INFORMATION CONTACT:

Ronald Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, Federal Energy Regulatory Commission. (202) 357-5321.

Howard Jack, Assistant General Counsel for Hydroelectric Licensing, Office of the General Counsel, Federal Energy Regulatory Commission. (202) 357-8448.

James Hoecker, Division of Regulatory Development, Office of the General Counsel, Federal Energy Regulatory Commission. (202) 357-9342.

The Federal Energy Regulatory Commission (Commission) proposes to establish procedures for exempting from all or part of Part I of the Federal Power Act (Act) certain small hydroelectric power projects (projects) having a proposed installed generating capacity of 5 megawatts or less. The rule would implement in part section 408 of the Energy Security Act of 1980 (ESA).[1] Under the rule as proposed, the Commission would provide such exemptions based on case-by-case determinations. The Commission will consider further rulemakings to exempt classes or categories of projects, as permitted by section 408(b) of the ESA.

I. Background

Title II of the ESA, also known as the Renewable Energy Resource Act of 1980, contains a provision that amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to authorize the Commission to exempt certain small hydroelectric power projects, on a case-by-case basis or by class or category of such projects, from all or part of Part I of the Act, including any licensing requirement.

Section 408 grants the Commission discretion to provide exemption under

[1] Pub. L. 96-294, 94 Stat. 611. Section 408 of the ESA amends *inter alia*, sections 405 and 408 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2705 and 2708).

the following specified conditions. The proposed installed capacity of an exemptible project may not exceed 5 megawatts. To be exemptible, a project must utilize the water power potential of an existing dam, unless it is a project that will utilize a so-called "natural water feature" that does not require the creation of a dam or man-made impoundment. Such a natural water feature will commonly be an elevated lake or a waterway the topographical features of which permit diversion of some water for purposes of power generation. Finally, section 408 provides that certain environmental requirements apply to those projects that the Commission exempts from licensing. Those requirements include the National Environmental Policy Act, the Fish and Wildlife Coordination Act, the Endangered Species Act and the consultation provisions in section 30 of the Federal Power Act that apply to exemption of small conduit hydroelectric facilities.

Prior to issuing this proposed rule, the Commission issued a Notice of the availability of a Draft rule and of Informal Conferences.[2] Pursuant to that notice, the Commission's staff took informal comments on the draft rule and related inquiries and held informal conferences on them in Washington, D.C. on August 1, 1980 and August 12, 1980. In formulating this Notice, the Commission has considered the various comments received. Those comments, including transcripts of the two conferences, are available for inspection in the public files of the Commission. The proposed rule utilizes case-by-case determinations based on information provided by individual applicants to provide exemptions for small hydroelectric power projects.[3] The Commission proposes to exempt small hydroelectric power projects in much the same way it now exempts small conduit hydroelectric facilities.[4]

II. Summary of the Rule, With Questions for Comment

The proposed rule applies to applications for exemptions of small hydroelectric power projects having a proposed installed generating capacity of 5 megawatts or less. A small hydroelectric power project is defined as a project located on non-Federal lands [5] that uses the water power potential of an existing dam or a natural water feature without need for a dam or man-made impoundment.

The applicability provision specifically states that a small hydroelectric power project that is part of any licensed multidevelopment hydroelectric power project does not qualify for exemption. The Commission requests comment on the implications of so limiting the applicability of the rule. Under what circumstances would exemption of integral portions of licensed projects be appropriate? If exemption from licensing were prohibited for such projects, from which other provisions of the Federal Power Act might exemption be reasonable and feasible?

The proposed rule defines the term "project" more narrowly than does section (3)(11) of the Act. Neither the ESA nor PURPA defines "project." However, both statutes state that a small hydroelectric power project relate to *an* existing dam, thereby implying that such a project involves a single impoundment. Under the proposed rule, a project would include only those facilities directly associated with a single man-made impoundment or a natural lake. Under section (3)(11) of the Act, a "complete unit of development" might include more than one impoundment and a series of

[2] 45 FR 49591, July 25, 1980.

[3] The Commission will consider further rulemakings that implement the provision in section 408(b) allowing the Commission to exempt "classes or categories" of projects, thereby obviating any application procedure.

[4] *See*, Order No. 76, 45 FR 28065, April 19, 1980.

[5] This rule does not extend to projects located at United States dams or which are located wholly or in part on lands which the United States owns in fee. The Commission is still considering the legal and policy implications of exemptions for those kinds of projects before proposing any rules covering them.

hydraulically coordinated dams. As stated above, a project, as defined by this rule, is not exemptible if it comprises part of such a multi-development licensed project, as the term "project" used in section (3)(11) of the act. Because the proposed definition of "project" is more circumscribed and therefore may include fewer generating units, eligibility for exemption will be greater than if "project" were construed to include all dams, impoundments, and powerhouses in a large coordinated unit of development. If there is no lake or impoundment, "project" is defined in the proposed rule to include the diversion structure and the facilities associated with it. The commission expects that the definitions in this rule will further the purposes of section 408 of the ESA to encourage small hydropower development.

The scope of the proposed definition of "project" is sufficiently broad to exclude from exemption any in a series of separately developed generation facilities that have an aggregate capacity in excess of 5 megawatts and that depend on the same impoundments. The National Alliance for Hydroelectric Energy has proposed [6] that such individual units be made exemptible. These developable sites could be distinguished from one another on the basis of separate ownership or historical use, the Alliance argues generally. The proposed rule does not accommodate this proposal because of the difficulties of establishing criteria for what constitutes such a separate "project" under separate ownership. The Commission acknowledges the Alliance's concern and asks for specific suggestions for resolving these difficulties. However, the Commission believes it is important that the rule not provide a means for subverting the 5 megawatt limitation on exemptible projects imposed by the Congress.

The statutory term "proposed installed capacity" is interpreted in the proposed rule to mean that an applicant must proposed to add some new generating capacity at a project in order for the project to qualify for an exemption. This would include proposals to install capacity where none existed previously, to replace or rehabilitate abandoned or inoperable existing capacity at a project, and to add capacity where there is existing operable capacity. This interpretation reflects the purpose of section 408 of the ESA to encourage development of hydropower. The proposed installed capacity will be computed as the sum of both newly developed capacity and existing capacity and may not exceed 5 megawatts in the aggregate.

Section 4.103 describes who may apply for an exemption and how such application will be treated in relation to other applications, permits, or licenses. Under the proposed rule only a person who has a property interest such as ownership in fee, a leasehold, easement, right-of-way, or an option to obtain such interest, sufficient to permit development of the project may apply for an exemption. This prevents a person who lacks the requisite property interest to develop the project from obtaining an exemption for another person's project.[7] The rule does not require that a person have such ownership interests in the entire project to be considered a "project owner." A person need only possess sufficient interest in the project to develop hydroelectric power at the site.

Section 4.103(b) of the proposed rule is designed to protect a person other than the project owner who has already applied for a permit or license, or who holds a permit, from being defeated by a project owner's untimely application for exemption from licensing. The Commission will accept an exemption

[6] Transcript, In the Matter of Section 408 of the Energy Security Act of 1980, August 12, 1980, Central Files (Docket No. RM80-65), Federal Energy Regulatory commission, at 47-50.

[7] Under Part I of the Federal Power Act and Part 4 of the Commission's regulations, a person need not have sufficient property interest to develop power at a site in order to obtain a preliminary permit or a license.

application or a notice of intent to file such application only if it is filed during the protest and intervention period prescribed in the public notice for the permit or license application. With this exception, the Commission will not accept any applications for exemption from licensing if, on the date such application is submitted, a person other than the project owner has an unexpired preliminary permit or license, or the Commission has accepted a preliminary permit or license application from a person other than the project owner.

On the other hand, a project owner who has filed for or obtained an exemption from licensing would be protected from permit or license applicants that would seek to take and develop the project. The Commission will not accept an application for a preliminary permit or license from a person other than the project owner if, on the date the application is submitted, the project is exempt from licensing or the Commission has accepted an application for exemption submitted by the project owner.

A project owner may convert an application for license to an application for exemption at any time during the period for filing protests and petitions for intervention prescribed in the public notice for the license application. A project owner may also apply for a license even if the project has been exempted. However, such a license application would then be open to competition.

Paragraph (b)(1)(v) of proposed § 4.103 contains noteworthy provisions about Commission treatment of applications that propose to develop the same project. An exemption application submitted in competition with, and during the public notice period for, an application for a preliminary permit will be preferred to the permit application. Likewise, the Commission will favor an exemption application that competes with an accepted license application, unless the license applicant would significantly better develop the water power potential at the project.

Municipalities or other public entities that are not project owners and that apply for preliminary permits or licenses that compete with exemption applications will be governed by the same rules as other applicants that are not project owners and will not receive the preferential treatment provided in § 4.33.

The protections for project owners in the proposed rule are greater than the alternative protections in the draft rule and also greater than alternatives proposed by the American Public Power Association (APPA) in its comments on the draft rule. Under the provisions of the draft rule, the project owner could not file an exemption application if a preliminary permit or license application by a non-owner had previously been accepted. The project owner could, however, file a competing permit or license application. But the draft rule contained no preference for the project owner who later filed for a permit or license. Both the proposed rule and the draft rule would preclude permit or license applications by non-owners if an exemption application has been accepted. Under APPA's alternative,[5] any application for exemption from licensing filed by a project owner that is neither a State nor a municipality would be subject to the State/municipal preference in section 7(a) of the Federal Power Act, if the plans of a competing State or municipality that is not a project owner were at least as well adapted to conserve and utilize in the public interest the water resources of the region. APPA also proposed that the Commission accept competing preliminary permit or license applications by a non-owner at any time during the 120 days following notice that a project owner's application for exemption from licensing is accepted for filing. The Commission specfically requests comments on the comparative merits of the three basic alternatives presented in the proposed rule, the draft rule, and in APPA's proposals.

Section 4.104 of the proposed rule contains the procedures and timing

[5] Transcript, *supra*, August 12, 1980, at 4.

provisions for Commission action on an application. Once an application is submitted, the Commission will allow only 45 days for correcting deficiencies. The Commission may on its own motion, or on the motion of any party in interest, order a hearing on an application for exemption. Interested agencies will have 60 days to comment on an application. If an agency does not comment within the 60 days, the agency will be presumed to have no objection to the exemption requested. If the Commission does not act within 120 days of the notice that an application is accepted, it is automatically granted on certain standard conditions.

The proposed rule specifies, in § 4.105, four standard conditions of every exemption. The installation of new capacity at the exempted project must begin within one year of the date of issuance of the exemption. Failure to begin development of the project on a timely basis may lead to revocation of the exemption. The Commission may also revoke an exemption for a project if construction or development of the exempted facilities is not completed within 4 years from the date of issuance of an exemption. These provisions are designed to prevent tying up the project site for an unreasonable time without development. The Commission believes that the periods allowed are reasonable to develop a project. Other standard conditions relate to the Commission's enforcement powers, compliance with conditions imposed by fish and wildlife agencies, and the navigation servitude of the United States to which all exempted projects on navigable waters remain subject.

The Commission may provide further (non-standard) conditons in each exemption based on the circumstances of the exemptible project, under § 4.104(f). For example, the Commission will be concerned about the safety of project works. If a project contains a dam that is 10 or more meters in height above streambed, impounds 2.5 million or more cubic feet of water, or is determined to have a high hazard potential, the Commission may require periodic inspection of the project by an independent consultant.[9]

The proposed rule describes the required format and contents of the application for exemption in § 4.106. The application includes an introductory statement, which identifies the applicant and the project, as well as Exhibits A, B, E, and G.

Exhibit A must include a description of the facility and the proposed mode of operation. Exhibit B is a general location map.

Exhibit E is an environmental report submitted to facilitate compliance with the National Environmental Policy Act. It also contains information to facilitate compliance with the National Historic Preservation Act, the Endangered Species Act, and the Fish and Wildlife Coordination Act. In granting exemptions, the Commission must comply with these statutes.

Exhibit G is a set of drawings showing structures and equipment. These drawings will permit the Commission to review the project structures, existing and proposed, in order to understand their environmental and dam safety implications.

Any applicant for exemption from selected parts of the Act other than the licensing requirements could request a waiver under § 1.7 of the Commission's regulations for those informational requirements in § 4.106 that were not relevant to the limited exemption sought.

This notice also proposes to delegate to the Director of the Office of Electric Power Regulation the limited authority to approve applications for exemptions from all or part of Part I of the Act, provided an environmental impact statement is not required, for small hydroelectric power projects or small conduit hydroelectric power projects.

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[9] These criteria are in Subpart D of the Commission's proposed Regulations Governing the Safety of Water Power Projects and Project Works, issued June 16, 1980, 45 FR 41608, June 19, 1980 (docket No. RM80-31).

III. Comment Procedure

Interested persons are invited to submit written views, comments, or suggestions in writing concerning all or part of the regulations proposed in this notice.

An original and 14 copies of all comments should be filed with the Secretary not later than September 29, 1980, at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should indicate the name, title, mailing address, and telephone number of the person to whom communications concerning the proposal may be addressed. Comments should reference Docket No. RM80–65 on the outside of the envelope and on all documents submitted to the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington D.C. 20426 during regular business hours.

A public hearing concerning this proposed rule will be held at 825 North Capitol Street, N.E., Washington D.C. 20426 on September 23, 1980, beginning at 10 a.m. The room number will be posted on that day. Any person interested in this proceeding or representing a group with such an interest may make a presentation at the hearing, provided a written request to participate is submitted to the Secretary of the Commission by September 19, 1980. Requests to participate should refer to Docket No. RM80–65. Participants are asked to supply the panel and the reporter with written copies of their comments. The hearing will not be a judicial evidentiary-type hearing. There will be no cross-examination of participants but the panel may ask questions of those presenting their views. The hearing will be open to the public. A transcript of the proceeding will be made available to the public through the Commission's Division of Public Information.

(Energy Security Act of 1980, Pub. L. 96–294, 94 Stat. 611; Federal Power Act, as amended, 16 U.S.C. 792–828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; and the Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142 (1978))

By direction of the Commission.

Keneth F. Plumb,

Secretary.

1. Part 4 is amended in the Table of Contents by adding subpart K to read as follows:

PART 4—LICENSES, PERMITS, AND DETERMINATION OF PROJECT COSTS

Subpart K—Exemption of Small Hydroelectric Power Projects of 5 Megawatts or Less

Sec.
4.101 Purpose and applicability.
4.102 Definitions.
4.103 Filing exemption applications.
4.104 Action on exemption applications.
4.105 Standard terms and conditions of exemption.
4.106 Contents of application.

2. Part 4 is amended by adding Subpart K to read as follows:

Subpart K—Exemption of Small Hydroelectric Power Projects of 5 Megawatts or Less

§ 4.101 Purpose and applicability.

(a) This subpart implements the amendments to sections 405 and 408 of the Public Utility Regulatory Policies Act of 1978 (PURPA) contained in Title IV of the Energy Security Act of 1980. The purpose of that title is to encourage development of renewable energy resources, including development of water resources for electric power generation. This subpart provides a procedure for obtaining exemption from all or part of Part I of the Federal Power Act (Act) for certain small hydroelectric power projects on a case-by-case basis, pending development of exemptions for classes or categories of such projects.

(b) This subpart applies to any small hydroelectric power project, as defined

in this subpart, except any single impoundment and any associated dam and other facility that are part of a licensed project that contains two or more impoundments and associated dams and facilities.

§ 4.102 Definitions.

For the purposes of this subpart—

(a) "Dam" means any structure for impounding water.

(b) "Existing dam" has the meaning set forth in section 408(a)(6) of PURPA.

(c) "Fish and wildlife agencies" means the U.S. Fish and Wildlife Service, the National Marine Fisheries Service if anadromous or estuarine fish may be affected, and any state agency with administrative authority over fish and wildlife resources of the state or states in which the small hydroelectric power project is or will be located.

(d) "Non-Federal lands" means any lands except lands to which the United States holds fee title.

(e) "Project means:

(1) the impoundment and any associated dam, intake, water conveyance facility, power plant, primary transmission line, and other appurtenant facility, if a lake or similar natural impoundment or a man-made impoundment is used for power generation; or

(2) any diversion structure and any associated water conveyance facility, power plant, primary transmission line, and other appurtenant facility, if a natural water feature other than a lake or similar natural impoundment is used for power generation.

(f) "Project owner" means any citizen or association of citizens of the United States, state, municipality, or corporation incorporated under the laws of the United States or a state, that has real property interests, such as ownership in fee, easement, right-of-way, or leasehold, sufficient to permit development of the small hydroelectric power project, or an option to obtain such property interests.

(g) "Small hydroelectric power project" means any water power project located on non-Federal lands in which capacity will be installed or increased after the date of application under this subpart and which will have a total installed capacity of not more than 5 megawatts and that:

(1) utilizes for electric power generation the water power potential of an existing dam that is not owned by the United Stats or operated by any instrumentality of the Federal Government, including the Tennessee Valley Authority; or

(2) utilizes or proposes to utilize a natural water feature for the generation of electricity, without the need for any dam or man-made impoundment.

§ 4.103 Filing exemption applications.

(a) *Who may apply.* Any project owner of a small hydroelectric power project may apply for exemption of that project from all or part of Part I of the Act, including licensing.

(b) *Relationship to other applications, permits, and licenses.* For purposes of this subpart, the Commission will treat preliminary permit and license applications, preliminary permits, licenses, and applications for exemption from licensing that are related to a small hydroelectric power project as follows:

(1) *Pending permit or license application or outstanding preliminary permit or license.* (i) Except as provided in clause (ii), the Commission will not accept for filing any application for exemption from licensing if there is on the date that application is submitted:

(A) an unexpired preliminary permit or license for the small hydroelectric power project held by a permittee or licensee other than the project owner; or

(B) an accepted preliminary permit or license application for the small hydroelectric power project submitted by an applicant other than the project owner.

(ii) (A) If an applicant other than the project owner has filed, and the Commission has accepted, an application for a preliminary permit or license for a small hydroelectric power project, the project owner may submit an application for exemption from licensing, or a notice of intent to file

such an application, as described in this paragraph. Such application or notice must be submitted not later than the last date for filing protests or petitions to intervene prescribed in the public notice issued under § 4.31(c)(3) for the preliminary permit or license application.

(B) Any project owner that files a conforming notice of intent under this paragraph must submit the application for exemption not later than 120 days after the last date for filing protests or petitions to intervene prescribed in the public notice of the preliminary permit or license application.

(C) Any notice of intent to submit an application for exemption from licensing must conform to the requirements of § 4.33(b) and contain a sworn statement that the prospective applicant is the project owner, as defined in § 4.102(f). The notice of intent and the subsequent application for exemption from licensing must be accompanied by proof of service of a copy of the notice or application on the person specified in § 4.33(d)(3).

(iii) If the project owner has filed, and the Commission has accepted, an application for license for a small hydroelectric power project, the project owner may convert that application to an application for exemption from licensing by so notifying the Commission in writing and submitting documentary evidence showing that the applicant is the project owner. Such notice and documentation must be submitted not later than the last date for filing protests or petitions to intervene prescribed in the public notice of the license application issued under § 4.31(c)(2) of this chapter.

(iv) Any accepted license or preliminary permit application submitted by a project owner that later applies for exemption of the small hydroelectric power project from licensing will retain its validity and priority under Subpart D of this part until the project owner withdraws the license or preliminary permit application or the small hydroelectric power project is exempted from licensing under this subpart.

(v) (A) If an accepted application for a preliminary permit and an accepted application for exemption from licensing propose to develop mutually exclusive small hydroelectric power projects, the Commission will favor the applicant for exemption.

(B) If an accepted application for a license and an accepted application for exemption from licensing propose to develop mutually exclusive small hydroelectric power projects, the Commission will favor the applicant for exemption unless the plans for the license applicant would significantly better develop the water power potential of the water resources at the project.

(2) *Pending exemption application or outstanding exemption.* (i) Except as permitted under clause (iii), the Commission will not accept a preliminary permit or license application for any small hydroelectric power project that is submitted by any applicant other than the project owner if, on the date of the application is submitted:

(A) such project is exempt from licensing, under this subpart; or

(B) the Commission has accepted an application submitted by the project owner for exemption of that project from licensing.

(ii) A project owner may at any time submit a preliminary permit or license application for its small hydroelectric power project, even if the project is exempt from licensing under this subpart or the project owner has submitted an application for exemption of that project from licensing. Any pending application for exemption from licensing of the small hydroelectric power project will be considered withdrawn as of the date that the Commission accepts for filing a preliminary permit or license application submitted by the project owner.

(iii) If the project owner submits a preliminary permit or license application for a small hydroelectric power project, competing preliminary permit or license applications may be submitted under § 4.33 of this part by applicants other than the project owner.

§ 4.104 Action on exemption applications.

(a) An application for exemption for a small hydroelectric power project will be processed in accordance with paragraphs (c) through (g) of § 4.31 of this part, except that notice will be published only once in a daily or weekly newspaper of general circulation in each county in which the project is or will be located. The additional time that may be allowed under § 4.31(d) of this part for correcting deficiencies in an application for exemption may not exceed 45 days.

(b) The Commission may order a hearing on an application for exemption either on its own motion or on the motion of any party in interest. Any hearing shall be limited to the issues prescribed by the order of the Commission.

(c) the Commission will circulate a notice of application for exemption to interested agencies at the time the applicant is notified that the application is accepted for filing. Fish and wildlife agencies will also receive copies of the application. If a particular agency does not comment within 60 days from the date of issuance of the notice, that agency will be presumed to have no comment on or objection to the exemption requested. A fish and wildlife agency that does not comment within that time will also be presumed to have determined that no terms or conditions of exemption are necessary to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the provisions of the Fish and Wildlife Coordination Act, except those terms or conditions that may be included in Exhibit E of the application of exemption.

(d) If the Commission has not taken one of the actions set forth in paragraph (e) of this section within 120 days after notifying the applicant that its application for exemption is accepted for filing, the requested exemption will be deemed to be found consistent with the public interest and the application will be considered granted as requested, on the standard terms and conditions set forth in § 4.105.

(e) Within 120 days after notifying an applicant that its application for exemption is accepted for filing, the Commission may take any of these affirmative actions:

(1) grant the exemption as requested;

(2) grant an exemption from provisions of Part I of the Federal Power Act (and the regulations issued under those provisions) other than those for which exemption was requested, upon finding that modification of the exemption requested is in the public interest;

(3) deny exemption if the granting of the exemption would be inconsistent with the public interest; or

(4) suspend the 120-day period for action under this paragraph, upon finding that additional time is necessary for gathering additional information, conducting additional proceedings, or deliberating on the issues raised by the application.

(f) In granting an exemption the Commission may prescribe terms or conditions in addition to those set forth in § 4.105 in order to:

(1) protect the quality or quantity of the related water supply;

(2) otherwise protect life, health, or property;

(3) avoid or mitigate adverse environmental impact; or

(4) better conserve, develop, or utilize in the public interest the water power resources of the region.

§ 4.105 Standard terms and conditions of exemption.

Any exemption granted under this subpart for a small hydroelectric power project is subject to the following standard terms and conditions:

(a) *Article 1.* The Commission reserves the right to conduct investigations under sections 4(g), 306, 307, and 311 of the Federal Power Act with respect to any acts, complaints, facts, conditions, practices, or other matters related to the construction, operation, or maintenance of the exempt project. If any term or condition of the exemption is violated, the Commission may revoke the exemption, issue a suitable order under section 4(g) of the

Federal Power Act, or take appropriate action for enforcement, forfeiture, or penalities under Part III of the Federal Power Act.

(b) *Article 2.* The construction, operation, and maintenance of the exempt project must comply with any terms and conditions that any Federal or state fish and wildlife agencies have determined are appropriate to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the purposes of the Fish and Wildlife Coordination Act.

(c) *Article 3.* The Commission may revoke this exemption if the project owner has not begun actual construction or development of any proposed generating facilities within one year, or completed construction or development of such proposed facilities within four years, from the date on which the exemption was granted.

(d) *Article 4.* This exemption is subject to the navigation servitude of the United States if the project is located on navigable waters of the United States.

§ 4.106 Contents of application.

(a) *General requirements.* (1) An application for exemption under this subpart must contain the introductory statement and exhibits described in this section and an appendix containing documentary evidence showing that the applicant is the project owner. An application for exemption of a small hydroelectric power project must conform to the requirements set forth in §§ 1.5 and 1.14 through 1.17 of this chapter.

(2) An original and fourteen copies of the exemption application must be submitted to the Secretary of the Commission, and a copy must be served at the same time on the Commission's regional engineer for the region in which the project is located. Full-sized prints of all required maps and drawings must be filed with the application. Maps and drawings need not conform to the requirements of § 4.32 of this part, but must be of sufficient size, scale, and quality to permit easy reading and understanding. The Commission will request original drawings (microfilm) when it notifies the applicant that the application is accepted.

(b) *Introductory Statement.* The applicant must submit an introductory statement that conforms to the following format:

Before the Federal Energy Regulatory Commission

Application for Exemption of Small Hydroelectric Power Project

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for an exemption for [name of project], a small hydroelectric power project that is proposed to have an installed capacity of 5 megawatts or less, from certain provisions of the Federal Power Act. [If applicable: The project is currently licensed as FERC Project No. ———.]

(2) The location of the project is:

[State or territory] ———
[County] ———
[Township or nearby town] ———
[Stream or body of water] ———

(3) The exact name and business address of each applicant are:

———
———
———

(4) The exact name and business address of each person authorized to act as agent for the applicant in this application are:

———
———
———

(5) [Name of applicant] is [specify, as appropriate: a citizen of the United States; an association of citizens of the United States; a municipality; a state; or a corporation incorporated under the laws of (specify the United States or the state of incorporation, as appropriate)] and is the project owner.

(6) The provisions of Part I of the Federal Power Act for which exemption is requested are:

[List here all sections or subsections for which exemption is requested; or, if all, state "All".]

(c) *Exhibit A.* Exhibit A must describe the small hydroelectric power project

and its proposed mode of operation. To the extent feasible, the information in this exhibit may be submitted in tabular form. The applicant must submit the following information:

(1) A brief description of any existing dam and impoundment proposed to be utilized by the small hydroelectric power project and any other existing or proposed project works and appurtenant facilities, including intake facilities, diversion structures, powerhouses, primary transmission lines, penstocks, pipelines, spillways, and other structures, and the sizes, capacities, and construction materials of such structures.

(2) The number of existing and proposed generating units at the project, including auxiliary units, the capacity of each unit, any provisions for future units, and a brief description of any plans for retirement or rehabilitation of existing generating units.

(3) The type of each hydraulic turbine.

(4) A description of how the power plant is to be operated, that is, run-of-river or peaking.

(5) A graph showing a flow duration curve for the project or, if flow data are not available from United States Geological Survey records, the estimated average annual stream flow in cubic feet per second.

(6) Estimations of:

(i) the average annual generation in kilowatt hours;

(ii) the average and design head of the power plant;

(iii) the hydraulic capacity of each turbine of the power plant (flow through the plant) in cubic feet per second;

(iv) the number of surface acres of the man-made or natural impoundment used, if any, at its normal maximum surface elevation and its net and gross storage capacities in acre-feet.

(7) The planned date for beginning and completing the proposed construction or development of generating facilities.

(8) A description of the nature and extent of any repair, reconstruction, or other modification of a dam that would occur in association with construction or development of the proposed small hydroelectric power project, including a statement of the normal maximum surface area and normal maximum surface elevation of any existing impoundment before and after construction.

(d) *Exhibit B.* Exhibit B is a general location map that must show the following information:

(1) The location of the existing and proposed physical structures of the small hydroelectric power project, including any dam or diversion structure, reservoir or impoundment, penstocks, pipelines, power plants, access roads, transmission lines, and other important features.

(2) The relationship of the project structures to the stream or other body of water on which the project is located and to the nearest town or any permanent monuments or objects, such as roads, transmission lines, or other structures, that can be readily recognized in the field.

(3) A description of who owns or has other property interests in any tract of land occupied by the project.

(e) *Exhibit E.* This exhibit is an environmental report that must include the following information, commensurate with the scope and environmental impact of the construction and operation of the small hydroelectric power project:

(1) A description of the environmental setting in the vicinity of the project, including vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational uses, socio-economic conditions, historical and archeological resources, and visual resources.

The report must give special attention to endangered or threatened plant and animal species, critical habitats, and sites eligible for or included on the National Register of Historic Places. The applicant may obtain assistance in the preparation of this information from state natural resources agencies, the state historic preservation officer, and

from local offices of Federal natural resources agencies.

(2) A description of the expected environmental impacts resulting from any proposed construction or development and any changes in the operation of small hydroelectric power project with existing installed capacity, or from the proposed construction and operation of a small hydroelectric power project without any existing installed capacity, including a discussion of the specific measures proposed by the applicant, the agencies, and others to protect and enhance environmental resources and to mitigate adverse impacts of the project on them.

(3) Letters or other documentation showing that the applicant consulted or attempted to consult with fish and wildlife agencies before filing the application, including any terms or conditions of exemption that those agencies have determined are appropriate to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the provisions of the Fish and Wildlife Coordination Act. If any fish or wildlife agency fails to provide the applicant with documentation of the consultation process within a reasonable time, in no case less than 30 days, after such documentation is requested, the applicant may submit a summary of the consultation and any determinations of the agency. Any exemption application that does not contain the information required in this subparagraph will be considered patently deficient and rejected pursuant to § 4.31(d) of this part.

(4) Any additional information the applicant considers important.

(f) *Exhibit G.* Exhibit G is a set of drawings showing the structures and equipment, that is, the proposed and existing project works, of the small hydroelectric power project. The drawings must include plan, elevation, profile, and section views of the power plant and any other principal structure and of any existing dam.

PART 375—THE COMMISSION

3. Section 375.308 is amended by adding a new paragraph (ll) to read as follows:

§ 375.308 Delegations to the Director of the Office of Electric Power Regulations.

The Commission authorizes the Director of the Office of Electric Power Regulation, or in the Director's absence, the Director's desigree to:

* * * * *

(ll) Grant or grant with modifications, but not to suspend the time for action on or to deny, any uncontested application submitted under Subparts J or K of Part 4 of this Chapter for exemption from all or part of Part I of the Federal Power Act, if an environmental impact statement is not required.

¶ 32,079 Regulations to Amend Filing Requirements for Interstate Pipelines Respecting the Incurrence of Production, Production-Related, and Non-allocable Costs

45 F. R. 61641 (September 17, 1980).

18 CFR Part 154

[Docket No. RM80-76]

Regulations To Amend Filing Requirements for Interstate Pipelines Respecting the Incurrence of Production, Production-Related, and Non-allocable Costs

Issued September 9, 1980.

AGENCY: Federal Energy Regulatory Commission; DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission proposes to amend § 154.63 of its regulation to require filing of certain information by an interstate pipeline as part of any rate request or amendment. The information, to be filed on a new proposed schedule, would include data as to the types of activities performed by the pipeline and costs incurred for those activities. The proposed amendment is an outgrowth of Commission rules and policy recently issued under Docket No. RM80-47, "Regulations implementing Section 110 of the Natural Gas Policy Act of 1978 and Establishing Policy under the Natural Gas Act", 45 FR 53099 (Aug. 11, 1980).

DATE: Comment period closes October 24, 1980.

ADDRESSES: Comments should reference Docket No. RM80-76 and should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Written comments submitted in this proceeding will be available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

FOR FURTHER INFORMATION CONTACT: John Conway, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100-K, 825 North Capitol Street, NE., Washington, D.C. 20426.)202) 357-8150.

By this Notice, the Federal Energy Regulatory Commission (the Commission) proposes to amend§ 154.63 of its regulations. The amendment would require filing of certain information by interstate pipelines that incur production costs, non-allocable costs, and production-related costs. The amendment provides that certain information must be filed by interstate pipelines. In addition, the amendment specifically references the recently issued policy of § 2.102 of the regulations.[1]

A. Background

Order No. 94 established a policy under the Natural Gas Act for interstate pipelines in the lower-48 states. The policy provides that:

> If an interstate pipeline purchases natural gas in a first sale, then, in any proceeding brought under the Natural Gas Act to determine the lawfulness of the rates and charges of such pipeline, any activity that results in the pipeline incurring a production-related cost with respect to such gas (whether or not the activity for which the cost is incurred is conducted by the pipeline) shall be deemed prudent if: (1) the activity is one the cost of which could have been applied for under Subpart K of Part 271 had it been undertaken by the seller; or (2) the cost incurred is a prudent compression cost.[2]

[1] Section 2.102 was issued as part of Order No. 94, "Regulations Implementing Section 110 of the Natural Gas Policy Act of 1978 and Establishing Policy under the Natural Gas Act," Docket No. RM80-47 (issued July 25, 1980), 45 FR 53099 (August 11, 1980).

[2] Order No. 94 at 78, § 2.102(a), 45 F.R. at 53114.

For purposes of the policy, the terms "first sale" and "interstate pipeline" have the same meanings as those terms have under the Natural Gas Policy Act of 1978 (the NGPA);[3] and the term "production-related cost" has the same meaning as that term has under § 270.102(b)(17) of the Commission's regulations.[4]

The policy of § 2.102 is an outgrowth of the Commission's rules to implement section 110(a)(2) of the NPGA.[5] Under section 110(a)(2), the Commission has discretion to permit sellers of natural gas to charge prices in excess of NGPA-established ceiling prices in order to allow sellers to recoup production-related costs borne by them. Yet section 110 applies only to costs borne by the seller of the gas. There may also be situations in which costs are incurred by the purchaser of the gas because certain activities are not performed by the seller. It was to deal with this latter situation for interstate pipelines that purchase gas in a first sale that the Commission established the policy of § 2.102.[6]

The policy of § 2.102 describes what production-related activities will be deemed prudent if performed by an interstate pipeline. Two major categories of activities are provided for. The first is for activities that, had they been done by the seller, the seller could have applied under Subpart K of Part 271 for their costs. The second is for certain activities undertaken to compress the natural gas.[7] The policy statement thus recognizes, as a general proposition, that these two categories of activities should be deemed prudent and, consequently, should not be subject to challenge except with respect to the amount expended.

In order to properly implement the policy of § 2.102, a pipeline should file information as part of its case in chief as to costs incurred after its purchase of natural gas and whether those costs, and the activities that engendered those costs, should be borne by the pipeline's gas customers. The present general filing requirements (found under § 154.63 of the Commission's regulations) do not now provide for the filing of such information.

B. Description of the Proposed Rule

Section 154.63 of the regulations would be amended to require an additional statement, "Statement R—Production-Related Costs." If a pipeline purchases natural gas in a first sale and then incurs costs prior to its sale of the

[3] *See* Order No. 94 at 78, § 2.102(b)(1), 45 FR at 53114.

[4] *Id.* at 79, § 2.102(b)(3), 45 FR at 53114. Section 270.102(b)(17) defines "production-related costs" to mean "costs (excluding production costs and non-allocable costs) of compressing, gathering, processing, treating, liquefaction, conditioning, or transporting natural gas or other similar costs." *See* Order No. 94 at 80, 45 FR at 53114–53115.

[5] These rules appear under Subpart K of Part 271 of the Commission's regulations; *see* particularly §§ 271.1100, 271.1104 and 271.1105, as amended, Order No. 94 at 81, 82–88, 45 FR at 53115–53116.

[6] *See* Order No. 94 at 59–63 and Appendix thereto, 45 FR at 53111–53113.

[7] The "prudent compression cost" of the policy statement is defined as any compression cost that:

(i) is not a production cost;

(ii) is properly allocable to the gas stream purchased by the pipeline for the benefit of its gas consumers; and

(iii) is in one of the following categories:

(A) a compressor or compression facility serving two or more onshore producing wells, leases or fields or more than one offshore producing platform and necessary to pressurize the gas for pipeline entry absent any treatment, processing, or conditioning but only to the extent the cost so incurred is the least cost of compression practicable;

(B) compression necessary to treat, process, or condition the gas but only to the extent such treatment, processing, or conditioning is necessary to exceed the minimum quality standards set forth under § 271.1104(c)(4);

(C) compression necessary because of pressure loss attributable to treating, processing, or conditioning the gas stream but only to the extent that such treatment, processing, or conditioning was necessary to exceed the minimum quality standards set forth under § 271.1104(c)(4); or

(D) a compressor or compression facility that is not necessary for or because of any treatment, processing, or conditioning but operates on a transporting system to decrease upstream line pressure.

gas that would have been production costs, non-allocable costs or production-related costs if incurred by the seller, then the information required by Statement R would be filed.[8] The information supplied by Statement R would include an identification of the activities involved and the total level of costs incurred by the pipeline for those activities. For those activities that are "production-related" additional information, segregated by seller's contract, or producing field or area (as may be appropriate), would be supplied. For this category, the nature of the activities involved, the total costs incurred for each activity (including investment costs), the apportionment of those costs to gas customers (as opposed to oil, gas liquid or other non-gas customers) and the methods used to apportion the costs would be given. In addition, any method used to assign direct or indirect costs to the activities would be given.

It is proposed that the information given for production-related activities and costs should be of such detail as to permit a finding that the activities undertaken by the pipeline are prudent activities for which gas customers should bear the costs. The standards enumerated under the policy of § 2.102 may be used to this end. For activities not deemed prudent under the policy statement of § 2.102, and for the amount of all costs claimed as being attributable to gas customers, the pipeline must provide such information as would support a finding that these activities and costs are prudent.

As described here, the filing requirements of new Statement R would apply only to interstate pipelines that purchase natural gas in a first sale. The information to be supplied on Statement R may also be of practical use in decisions respecting the pricing of gas that is produced by a pipeline rather than purchased by the pipeline in a first sale, and for which NGPA rate treatment is available.[9] Comments on the application of the proposed filing requirements of new Statement R for such pipeline producers are therefore specifically requested.

C. Public Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80–76. An original and 14 copies should be filed. Comments should be received on or before October 24, 1980. Comments so received will be considered by the Commission prior to the promulgation of a final rule under this Docket.

All written submissions will be placed in the public file which has been established in this Docket and will be available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

(Natural Gas Act as amended, 15 U.S.C. 717, *et. seq.*; Department of Energy Organization Act, 47 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267)

[8] "Production costs" are defined as "all costs incurred for exploration, development, production and abandonment operations, enhanced recovery techniques (including costs of compression incurred in the production of stripper well natural gas to which the pricing provisions of Subpart H of Part 271 apply), gas-lift pumping or other liquid lifting equipment located on or in the vicinity of the wellhead or the point of commingling gas on the offshore platform from which the gas is produced, and costs that attend compression necessary for lifting liquids, cycling gas in a gas-condensate reservoir or pressurizing an oil reservoir." *See* § 270.102(b)(15), 45 F.R. 53114.

"Non allocable costs" are defined as "all costs incurred for the construction or operation of facilities to recover, separate, extract, process, treat, dehydrate, store, or transport crude oil or natural gas liquids or both." *See* § 270.102(b)(16), 45 F.R. 53114.

The definition of "production-related costs" was given above, see note 4 *supra*.

[9] *See* Order No. 98, "Final Rule Governing Pricing of Pipeline Production Under the Natural Gas Act", Docket No. RM80-6 (issued August 4, 1980), 45 FR 53091 (Aug. 11, 1980).

In consideration of the foregoing, Part 154 of Chapter I, Title 18, Code of Federal Regulations, is proposed to be amended as set forth below.

By Direction of the Commission.

Kenneth F. Plumb,

Seretary.

1. Section 154.63 is amended in paragraph (b)(3) by inserting at the end of the third sentence a new sentence to read as follows:

§ 154.63 Changes in a tariff, executed service agreement or part thereof.[1]

* * * * *

(b) *Material to be submitted.* * * *

(3) *Major rate increase.* * * *

Statement R is required to be submitted by all classes of companies. * * *

2. Section 154.63 is further amended by adding to the end of paragraph (f) a new schedule to read as follows:

§ 154.63 Changes in a tariff, executed service agreement or part thereof.[1]

* * * * *

(f) *Description of statements.* * * *

Statement R—Production-related costs. If a pipeline purchases natural gas in a first sale and incurs costs prior to the sale of the gas so purchased which, had they been incurred by the seller of the gas, would have been "production costs", "non-allocable costs", or "production-related costs", as defined in § 270.102(b)(15), (16) and (17) of this chapter, the pipeline shall submit data describing each of the costs and the activity related to such cost. In the case of costs that are "production-related" the data shall be segregated by seller's contract, or producing field or area (as may be appropriate), and shall describe: the nature of the activities involved; the total costs incurred for each activity (including investment costs); the costs apportioned to natural gas customers and a description of the methodologies used to apportion those costs to natural gas customers, and methodologies used (if any) to assign direct and indirect costs to the activities. The identification of the production-related activities, and the amounts expended therefor, is to be in such detail as to show that they are prudent activities for which customers should bear the cost. For those activities deemed prudent in § 2.102 of Part 2, the standards specified in that section may be used. For activities not deemed prudent under § 2.102, and for the amount of all costs claimed as being attributable to natural gas customers, the pipeline shall provide such information as would support a finding that these activities and costs are prudent.

¶ 32,080 Special Rule Under Part 270: Production Costs and Maximum Lawful Prices in Sales Under the Natural Gas Policy Act of 1978

45 F. R. 61643 (September 17, 1980).

18 CFR Part 270

[Docket No. RM80-72]

Special Rule Under Part 270: Production Costs and Maximum Lawful Prices in Sales Under the Natural Gas Policy Act of 1978

Issued September 9, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission proposes to amend § 270.101(a) of its regulations implementing the Natural Gas Policy Act of 1978 (NGPA) to provide that any first sale of natural Gas (other than a sale of deregulated high-cost gas) that results in a purchaser bearing "production costs" in addition to the first sale price is a sale exceeding the maximum lawful price of the NGPA. The proposed rule, if implemented, would define costs that cannot be shifted to purchasers under the NGPA. The proposed amendment is an outgrowth of Commission rules and policy recently issued under Docket No. RM80-47, "Regulations Implementing Section 110 of the Natural Gas Policy Act of 1978 and Establishing Policy under the Natural Gas Act, 45 FR 53099 (August 11, 1980).

DATES: Comment period closes October 24, 1980.

ADDRESS: Comments should reference Docket No. RM80-72 and should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Written comments submitted in this proceeding will be available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

FOR FURTHER INFORMATION CONTACT: John Conway, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100-K, 825 North Capitol Street, NE., Washington, D.C. 20426. (202) 357-8150.

By this notice, the Federal Energy Regulatory Commission (Commission) proposes to amend its regulations issued under Part. 270. The proposed amendment would be to § 270.101(a), the general regulations implementing the Natural Gas Policy Act of 1978 (NGPA).[1] The proposed amendment would provide that any first sale (other than the sale of deregulated high-costs gas) that results in the purchaser bearing "production costs" in addition to the first sale price is a first sale exceeding the applicable maximum lawful price. The purpose of the proposed amendment is to complement the regulations implementing section 110 of the NGPA for production-related costs.

Background

On July 25, 1980, the Commission amended its regulations implementing section 110 of the NGPA.[2] Those amendments were to the provisions of Subpart K, Part 271 of the regulations that operate to permit sellers under the NGPA, lawful add-ons to their first sale prices for certain production-related costs.[3] In developing those amendments, the Commission concluded that:

[1] Pub. L. No. 95-621, 92 Stat. 3353 (1978), 15 U.S.C. 3301 *et seq.* (Sup.p. II 1978).

[2] Order No. 94, "Regulations Implementing section 110 of of the Natural Gas Policy Act of 1978 and Establishing Policy under the Natural Gas Act," Docket No. RM80-47 (issued July 25, 1980) 45 F.R. 53099 (Aug. 11, 1980).

[3] Section 110 of the NGPA provides in relevant part that "* * * a price for the first sale of natural gas shall not be considered to exceed the maximum lawful price applicable to the first sale of such natural gas * * * if such first sale price exceeds the maximum lawful price to the extent necessary to recover * * * any costs of compressing, gathering, processing, treating, liquefying, or transporting such natural gas, or other similar costs, borne by the seller and allowed for, by rule or order, by the Commission."

We believe that there are two types of costs outside the scope of section 110 and therefore not allowable under its provisions. These are costs incurred in the production and sale of nonnatural gas commodities (as, for example, costs allocable to oil and liquid production), and costs which are incurred for the wellhead production of natural gas. To grant an allowance under section 110 for either of these two types of activities would be a circumvention of the NGPA pricing provisions. With respect to costs for the production and sale of nonnatural gas commodities, these should be borne by the consumers of oil and liquids; and with respect to costs incurred for the wellhead production of natural gas, the costs should properly be borne by producers under NGPA ceiling prices.[4]

As a corollary to this conclusion, the Commission interpreted section 110's description of production-related costs as being costs "incurred only after the natural gas leaves the wellhead (i.e., is produced)."[5]

These conclusions were implemented in Order No. 94. The term "production-related costs" was defined to exclude "production costs" and "nonallocable costs."[6] The term "production costs" was defined as:

> * * * all costs incurred for exploration (including but not limited to geological and geophysical surveys, leasing, drilling, and equipping natural gas wells), development, production and abandonment operations, enhanced recovery techniques (including costs of compression incurred in the production of stripper well natural gas to which the pricing provisions of Subpart H of Part 271 apply), and lift or pumping equipment located on or in the vicinity of the wellhead or the point of commingling as on the offshore platform from which the gas is produced.

The regulations and policy issued in Order No. 94 addressed two aspects of the question of who should bear costs to produce natural gas and bring that gas to market. First, the regulation considered the case in which a first seller [7] incurs production-related costs.

The regulations of Subpart K were revised to provide a mechanism whereby the seller could increase its maximum lawful price to recoup some of these production-related costs.[8] Second, the Commission issued a policy statement under its Natural Gas Act authority to deal with the situation in which an interstate pipeline gas purchaser incurs the production-related costs instead of a seller.[9]

The regulations did not consider the case in which a producer-first seller attempts to shift to the purchaser costs that were incurred in producing the gas. That is, the regulations did not address the question of what costs, if any, for actually producing the gas should not be shifted to a purchaser by the producer.

B. The Proposed Rule

The Commission proposes to amend § 270.101 of its regulations implementing the NGPA by adding a new clause to § 270.101(a). The new clause, to be entitled "Special Rule for Production Costs," would provide that any first sale which shifts a production cost to the purchaser in a first sale is a sale that circumvents the ceiling price provisions of the NGPA. The amendment is based on the proposition that the ceiling prices of Title I of the NGPA, at the very least, provide for the recovery of costs

[4] Order No. 94, note 2 *supra* at 9, 45 FR at 53101.

[5] *Id.* at 14, 45 FR at 53102.

[6] *Id.* at 80, 45 FR at 53114–53115. 18 CFR 270.102(b)(17).

[7] Under section 2(21)(A) of the NGPA a "first sale" is defined as:

> any sale of any volume of natural gas—
>
> (i) to any interstate pipeline or intrastate pipeline;
>
> (ii) to any local distribution company;
>
> (iii) to any person for use by such person;
>
> (iv) which precedes any sale described in clauses (i), (ii), (iii), and
>
> (v) which precedes or follows any sale described in clauses (i), (ii), (iii), or (iv) and is defined by the Commission as a first sale in order to prevent circumvention of any maximum lawful price established under this Act.

Certain sales, such as those of volumes of natural gas from pipelines or local distribution companies, are not included in the definition of "first sale" unless they are sales of volumes of natural gas attributable to the production of these sellers; *see* section 2(21)(B) of the NGPA.

[8] Order No. 94, note 2 *supra* at 81–88, 45 FR at 53115–53116.

[9] *Id.* at 78–79, 45 FR at 53114.

incurred for finding and producing natural gas. Therefore, just as it would be an abuse of discretion to permit the add-on of a production cost under section 110 of the NGPA, it would be a violation of the ceiling price provisions to permit a seller to impose on a purchaser production costs that the seller has not incurred, and to do so by charging a first sale price and requiring the purchaser to subsequently incur the necessary production costs.

C. Comment Procedures

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80–72. An original and 14 copies should be filed. Comments should be received on or before October 24, 1980.

All written submissions will be placed in the public file that has been established in this docket and which is available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

The Commission intends to hold a public hearing on the amendment proposed in this notice as required by section 502 of the NGPA. The date and location of such hearing will be announced in the future. The amendment will not become final until the Commission has had the opportunity to receive oral presentations of relevant data, views and arguments.

(Natural Gas Policy Act of 1978; 15 U.S.C. 3301–3432 (Supp. II 1979))

In consideration of the foregoing, the Commission proposes to amend Part 270 of Chapter 1, Title 18, Code of Federal Regulations as set forth below.

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

Section 270.101 of Part 270 is amended by revising paragraph (a) to read as follows:

§ 270.101 Application of ceiling prices to first sales of natural gas.

(a) *Maximum lawful price.* (1) *General rule:* It is unlawful for any person to sell natural gas (other than deregulated high-cost gas) at a first sale price in excess of the highest maximum lawful price applicable to such gas under Part 271 of this chapter. No maximum lawful price applies to deregulated high-cost gas.

(2) *Special rule for production costs.* For purposes of this paragraph, any first sale of natural gas, other than a sale of deregulated high-cost gas, which results in a purchaser incurring production costs, in addition to the first sale price, is a sale of natural gas at a price in excess of the highest maximum lawful price applicable to such gas.

. . . . .

¶ 32,081 High-Cost Gas Produced From Tight Formations (Colorado)

45 F. R. 65606 (October 3, 1980).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-3)]

High-Cost Gas Produced From Tight Formations

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendations of the Colorado Oil and Gas Conservation Commission that the Mancos "B" formation be designated as a tight formation pursuant to § 271.703(d).

DATES: Comments on the proposed rule are due prior to October 23, 1980. Requests for hearing should be filed on or before October 8, 1980.

ADDRESS: Comments and requests for hearing must be filed with Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie J. Lawner (202) 357-8027 or Victor H. Zabel (202) 357-8559.

September 23, 1980.

I. Background

On August 28, 1980, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Niobrara formation underlying specified lands in Cheyenne, Kit Carson, Lincoln, Logan, Phillips, Sedgwick, Washington, and Yuma Counties, Colorado, be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Niobrara formation be designated a tight formation should be adopted. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

The recommended formation is located north and east of Denver, Colorado, on the eastern flank of the Denver-Julesberg Basin, and underlies all land in Cheyenne, Kit Carson, Lincoln, Logan, Phillips, Sedgwick, Washington, and Yuma Counties, Colorado. Gas production is from the chalk zone in the Smoky Hill member of the Upper Niobrara. The depth of the formation ranges from 1,300 feet and 3,000 feet.

II. Discussion of the Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the Smoky Hill in the Upper Niobrara formation at depths of 1300 feet to 3000 feet, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 277.703(c)(2)(i)(B); and

(3) Hydrocarbons usually do not exist as a liquid in the recommended formation. No well is expected to produce more than five (5) barrels of crude oil per day.

Colorado further asserts that typical casing design of wells drilled in the recommended formation, as required by Colorado's rules and regulations, will protect fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68, (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Niobrara formation,as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

III. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426, on or before October 23, 1980. Each person submitting a comment should indicate that the comments are being submitted in Docket No. RM79-76 (Colorado—3), and should give reasons including any supporting data for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data or otherwise particpate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Commission no later than October 8, 1980.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301—3342.))

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations

* * * * *

(d) *Designated tight formations.* (1) The following formations are designated as tight formations:

(i) [Reserved]
(ii) [Reserved]
(iii) [Reserved]
(iv) [Reserved]
(v) *Niobrara formation in Colorado.*—(A) *Delineation of formation.* The Niobrara formation is located north and east of Denver, Colorado, on the eastern flank of the Denver-Julesberg Basin, underlying all lands in Cheyenne, Kit Carson, Lincoln, Logan, Phillips, Sedgwick, Washington, and Yuma Counties, Colorado.

(B) *Depth.* The depth of the Niobrara formation ranges from 1300 feet to approximately 3000 feet.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,082 High-Cost Gas Produced From Tight Formations (Colorado)

45 F. R. 65607 (October 3, 1980).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-2)]

High-Cost Gas Produced From Tight Formations

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the National Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendations of the Colorado Oil and Gas Conservation Commission that the Mancos "B" formation be designated as a tight formation pursuant to § 271.703(d).

DATES: Comments on the proposed rule are due prior to October 23, 1980. Requests for hearing should be filed on or before October 8, 1980.

ADDRESS: Comments and requests for hearing must be filed with Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie J. Lawner (202) 357-8027 or Victor H. Zabel (202) 357-8559.

September 23, 1980.

I. Background

On August 29, 1980, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Mancos "B" formation underlying specified lands in Garfield and Rio Blanco Counties, Colorado, be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Mancos "B" formation be designated a tight formation should be adopted. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

The recommended formation is located approximately midway between Grand Junction and Rangely, Colorado, and straddles the Rio Blanco-Garfield County line from the Utah-Colorado state line east to the Douglas Pass and Baxter Pass Unit Areas. The proposed formation contains approximately 195,200 contiguous acres. The average depth to the top of the Mancos "B" formation is approximately 3475 feet.

II. Discussion of the Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Colorado on this matter demonstrates that:

(1) The average *in-situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the Mancos "B" formation at an average depth of 3475 feet, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 277.703(c)(2)(i)(B)); and

(3) Hydrocarbons usually do not exist as a liquid in the recommended formation. No well is expected to

produce more than five (5) barrels of crude oil per day.

Colorado further asserts that typical casing design of wells drilled in the recommended formation, as reguired by Colorado's rules and regulations, will protect fresh water aquifers.

Accordingly, prusuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68, (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Mancos "B" formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

III. Public Comment Procedures

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should reference Docket No. RM79-76 (Colorado-2). All comments and information received by the Commission prior to October 23, 1980 will be considered by the Commission prior to the issuance of the regulation.

Dates and locations of any hearings which may be held on this rulemaking will be announced in the near future. Any person wishing to present testimmony, views, data or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefor request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Commission no later than October 8, 1980.

(Natural Gas Policy Act of 1978 (15 U.S.C. 3301-3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d)(1) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* (1) The following formations are designated as tight formations:

(i) [Reserved]

(ii) [Reserved]

(iii) [Reserved]

(iv) [Reserved]

(v) *Mancos "B" formation in Colorado.*—(A) *Delineation of formation.* The Mancos "B" formation is located approximately midway between Grand Junction and Rangely, Colorado, and straddles the Rio Blanco-Garfield County line from the Utah-Colorado state line east to the Douglas Pass and Baxter Pass Unit Areas, underlying approximately 195,000 contiguous acres of land in Rio Blanco and Garfield Counties.

(B) *Depth.* The average depth to the top of the Mancos "B" formation is approximately 3475 feet.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,083 High-Cost Gas Produced From Tight Formations (Colorado)

45 F. R. 65608 (October 3, 1980).

18 CFR Part 271

[Docket No. RM79-76; Colorado-1]

High-Cost Gas Produced From Tight Formations

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendations of the Colorado Oil and Gas Conservation Commission that the Mancos "B" formation be designated as a tight formation pursuant to § 271.703(d).

DATES: Comments on the proposed rule are due prior to October 23, 1980. Requests for hearing should be filed on or before October 8, 1980.

ADDRESS: Comments and requests for hearing must be filed with Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie J. Lawner (202) 357-8027 or Victor H. Zabel (202) 357-8559.

September 23, 1980.

I. Background

On July 9, 1980, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), a recommendation that the "Wattenberg J Sand" formation underlying specified lands in Weld, Adams, and Boulder Counties, Colorado, be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the "Wattenberg J Sand" formation be designated a tight formation should be adopted. Colorado's recommendations and supporting data are on file with the Commission and are available to the public for inspection.

The recommended formation is located north and east of Denver, Colorado, on the western flank of the Denver-Julesberg Basin. The formation underlies approximately 883,200 contiguous acres of land in Boulder, Adams, and Weld Counties, Colorado. The average depth of the formation is 8,000 feet.

II. Discussion of the Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area averages .0059 millidarcies and is not expected to exceed .1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production in the proposed formation at an average of 8,000 feet, without stimulation, is not expected to exceed a maximum allowable production rate of 388 Mcf of gas per day; and

(3) Hydrocarbons usually do not exist as a liquid in the proposed area, therefore, no well is expected to produce more than five (5) barrels of crude oil per day.

Colorado further asserts that typical casing design of wells drilled in the recommended formation, as required by Colorado's rules and regulations, will protect fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the "Wattenberg J Sand" formation, as described and delineated in Colorado's recommendation filed with the Commission, be designated as a tight formation pursuant to § 271.703.

III. Public Comment Procedures

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Comments should reference Docket No. RM79-76 (Colorado-1). All comments and information received by the Commission prior to October 23, 1980, will be considered prior to the issuance of the regulation.

Dates and locations of any hearings which may be held on this rulemaking will be announced in the near future. Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and, therefore request a public hearing. Such request shall specify the amount of time requested for the presentation at the hearing. Requests for a hearing should be filed with the Commission no later than October 8, 1980.

(Natural Gas Policy Act (15 U.S.C. 3301-3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* (1) The following formations are designated as tight formations:

(i) [Reserved]

(ii) *Wattenberg J Sand formation in Colorado*—(A) *Delineation of Formation.* The Wattenberg J Sand formation is located north and east of Denver, Colorado on the western flank of the Denver-Julesberg Basin, underlying approximately 883,200 contiguous acres of land in Boulder, Adams and Weld Counties, Colorado.

(B) *Depth.* The "Wattenberg J Sand" formation ranges from a depth of 7,600' to 8,400'. The average depth is approximately 8,000'.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,084 First Sale Regulation Under Natural Gas Policy Act of 1978; Ceiling Prices (Texas)

45 F. R. 66811 (October 8, 1980).

18 CFR Part 271

First Sale Regulation Under Natural Gas Policy Act of 1978; Ceiling Prices

AGENCY: Office of Pipeline and Producers Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendations of the Texas Railroad Commission that the Canyon Sandstone formation be designated as a tight formation pursuant to § 271.703(d).

DATE: Comments on the proposed rule are due on November 1, 1980.

Public hearing: No hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 17, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299 or William Bushey, (202) 357–8590.

I. Background

On September 22, 1980, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 *Fed. Reg.* 56034, August 22, 1980), that the Canyon Sandstone formation, located in the western part of the state of Texas be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Canyon Sandstone formation be designated a tight formation should be adopted.

Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

The recommended formation is found in Crockett, Edwards, Schleicher, Sutton, Terrell and Val Verde Counties, Texas. To the south the boundary is the Texas-Mexico border and the eastern and southern county lines of Val Verde and Edwards Counties. The northern boundaries are the northern boundaries of Crockett and Schleicher Counties.

The boundary to the east is the eastern county lines of Schleicher, Sutton and Edwards Counties, and the western boundary is the western lines of Terrell and Crockett Counties. The two major fields within the Canyon Sandstone are the Ozona field and the Sonora field. The top of the Canyon Sandstone formation in the Ozona field is found at an average depth of 6180 feet in the north and 2675 feet in the south, and its thickness is approximately 380 feet in the north and 1240 feet in the south. The top of the recommended formation in the Sonora field is found at approximately 5900 feet in the north and 4775 feet in the sought, and its thickness is approximately 485 feet in the north and 1475 feet in the south.

II. Discussion of the Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of crude oil per day.

Texas further asserts that existing state and federal regulations assure that development of this formation will not adversely affect and fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Pursuant to § 271.703(b)(6) of the Commission's regulations, Texas stated that a limited portion of the recommended formation has been drilled consistent with field rules and a subsequent amendment to the field rules has reduced the size of the drilling units. Texas stated that it has no information that indicates that this portion of the recommended formation can be developed absent the incentive price.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68, (45 *Fed. Reg.* 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Canyon Sandstone formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

III. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426, on or before November 1, 1980. Each person submitting a comment should indicate that the comments are being submitted in Docket No. RM79-76 (Texas—2), and should give reasons including any supporting data for any supporting data for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Commission no later than October 17, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations

* * * * *

(d) *Designated tight formations.* (1) the following formations are designated as tight formations:

(i) through (v) [Reserved]

(vi) *Canyon Sandstone formation in Texas.*

(A) *Delineation of formation.* The Canyon Sandstone formation is found in Crockett, Edwards, Schleicher, Sutton, Terrell and Val Verde Counties, Texas.

(B) *Depth.* The top of the Canyon Sandstone formation in the Ozona field is at an average depth of 6180 feet in the north and 2675 feet in the south and ranges in thickness from approximately 380 feet in the north to 1240 feet in the south. The top of the Canyon Sandstone formation in the Sonora field is found at approximately 5900 feet in the north and 4775 feet in the south and the thickness ranges from approximately 485 feet in the north to 1475 feet in the south.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, and is also located in the official files of jurisdictional agency which submitted the recommendation.

¶ 32,085 Ceiling Prices; High Cost Natural Gas Produced From Tight Formations (Wyoming)

45 F. R. 66812 (October 8, 1980).

18 CFR Part 271

Ceiling Prices; High Cost Natural Gas Produced From Tight Formations Office of Pipeline and Producer Regulation

AGENCY: Federal Energy Regulatory Commission Department of Energy.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations are high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendations of the posed rulemaking contains the recommendations of the Wyoming Oil and Gas Conservation Commission that the Frontier and Mesaverde formations be designated as tight formations pursuant to § 271.703(d).

DATES:

Comment date: Comments on the proposed rule are due on October 23, 1980.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requestes for a public hearing are due October 10, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N. E., Washington, D. C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299 or Victor Zabel (202) 357–8559.

(Issued September 23, 1980.)

I. Background

On August 5 and 7, 1980, respectively the State of Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission, in accordance with § 271.703 of the final regulations (45 FR 56034, August 22, 1980), recommendations that the Frontier formation in Sweetwater, Unita and Lincoln Counties, Wyoming, (Wyoming—1), and the Mesaverde formation in Carbon and Sweetwater Counties, Wyoming, (Woyming—2), be designated as tight formations in the Commission's regulations. The United States Geological Survey joined in the designations. Pursuant to § 271.703(c)(4) this Notice of Proposed Rulemaking is hereby issued to determine whether the Commission should adopt Wyoming's recommendation that the Mesaverde and Frontier formations be designated as tight formations. Wyoming's recommendations and supporting data are on file with the Commission and are available for public inspection.

The vertical limits of the Frontier formation are defined by the Hilliard Shale above and the Mowry Shale below. The lands are located in portions of Sweetwater, Uinta and Lincoln Counties and are more fully described in the recommendations on file with this Commission and Wyoming.

The vertical limits of the Mesaverde formation are defined by the Lewis Shale above and Steele Shale below. The lands are located in portions of Sweetwater and Carbon Counties and are more fully described in the recommendations on file with this Commission and Wyoming.

II. Discussion of the Recommendations

Wyoming has made the recommendations that the Frontier and

Mesaverde formations be designated as tight formations based upon its findings that:

1. The estimated average in situ gas permeability throughout the formations' pay sections, is expected to be 0.1 millidarcy or less;

2. The stabilized production rate of wells completed for production in the formations without stimulation, is not expected to exceed the production rate determined in accordance with the Table found in § 271.703(c)(2)(i)(B) of the Commission's regulations; and

3. No well drilled into the recommended formations is expected to produce more than five (5) barrels of crude oil per day.

Wyoming also found that Rule 320 of the Wyoming Oil and Gas Conservation Commission Rules and Regulations assures that development of the recommended formations will not adversely affect fresh water aquifers. Rule 320 requires that surface casing of a well be run to a depth below all known or reasonably estimated utilizable domestic fresh water levels, and run to prevent blow-outs or uncontrolled flows.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Wyoming that the Frontier and Mesaverde formations, as described and delineated in Wyoming's recommendations filed with the Commission, be designated as tight formations pursuant to § 271.703.

III. Public Comment Procedures

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comment should reference Docket No. RM79-76 (Wyoming-1) or (Wyoming-2). All comments and information received by the Commission prior to October 23, 1980 will be considered prior to the issuance of the regulation.

Dates and locations of any hearings which may be held on this rulemaking will be announced in the near future. Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests for a hearing should be filed with the Commission no later than October 10, 1980.

(Natural Gas Policy Act, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Wyoming's recommendations are adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* (1) The following formations are designated as tight formations:

(i) [Reserved]

(ii) [Reserved]

(iii) *Frontier formation in Wyoming.*

(A) *Delineation of formation.* The Frontier formation is located in portions of Sweetwater, Uinta and Lincoln Counties, Wyoming.

(B) *Depth.* The top of the Frontier formation is marked by the Hilliard Shale and the bottom of the formation is marked by the Mowry Shale.

(iv) *Mesaverde formation in Wyoming.*

(A) *Delineation of formation.* The Mesaverde formation is located in portions of Carbon and Sweetwater Counties, Wyoming.

(B) *Depth.* The top of the Mesaverde formation is marked by the Lewis Shale and the bottom of the formation is marked by the Steele Shale.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,086 Ceiling Prices; High-Cost Gas Produced From Tight Formations (Colorado-4)

45 F. R. 69929 (October 22, 1980).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-4)]

Ceiling Prices; High-Cost Gas Produced From Tight Formations

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendations of the Colorado Oil and Gas Conservation Commission that the Fort Union, Mesaverde and the Mancos to the base of the Mancos "B" formations be designated as tight formations under § 271.703(d).

DATES: Comments on the proposed rule are due on November 10, 1980.

Public hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 27, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or Victor Zabel, (202) 357-8559.

October 10, 1980.

I. Background

On October 3, 1980, the Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Fort Union formation, the Mesaverde formation, and the Mancos formation to the base of the Mancos "B" Zone, of the Rio Blanco and Dry Gulch Units in Rio Blanco County, Colorado, be designated in the Commission's regulations as tight formations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that these formations be designated tight formations should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

The recommended formations are located in an area approximately 40 miles southwest of Meeker, Colorado and 30 miles northwest of R Colorado. The area is bounded on the north and south by synclinal and anticlinal trends, and on the northeast by an anticlinal closure known as Piceance Creek Dome. In addition, the area is made up of two federal units, the Dry Gulch and Rio Blanco Units.

The Fort Union formation is approximately 4000 to 5000 feet thick. The thickness of the Mesaverde ranges from approximately 4000 to 5000 feet at depth intervals of 5500 to 9000 feet. The Mancos formation (defined as being from the top of the Mancos to the base

of the Mancos "B" zone) is approximately 3000 feet thick at depth intervals of 9000 to 12,000 feet.

II. Discussion of the Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed areas is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of crude oil per day.

Colorado further asserts that the typical casing design of wells drilled in the area, as required by Colorado's rules and regulations, protects any fresh water aquifers in the area.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Fort Union formation, the Mesaverde formation, and the Mancos formation to the base of the Mancos "B" Zone as described and delineated in Colorado's recommendation as filed with the Commission, be designated as tight formations pursuant to § 271.703.

III. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426, on or before November 10, 1980.

Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado—4), and should give reasons including any supporting data for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Commission no later than October 27, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703 is amended by adding new paragraph (d)(1)(viii)–(x) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.*

(1) The following formations are designated as tight formations:

(i) through (vii) [Reserved]

(viii) *Fort Union Formation in Colorado.*

(A) *Delineation of formation.* The Fort Union formation is located in the Rio Blanco and Dry Gulch Units of Rio Blanco County, Colorado, approximately 40 miles southwest of Meeker, Colorado and 30 miles northwest of Rifle, Colorado. The area is bounded on the north and south by synclinal and anticlinal trends, and on the north-east by an anticlinal closure known as the Piceance Creek Dome.

(B) *Depth.* The average depth to the top of the Fort Union formation is approximately 4700 feet.

(ix) *Mesaverde formation in Colorado.*

(a) *Delineation of formation.* The Mesaverde formation is located in Rio Blanco and Dry Gulch Units of Rio Blanco County, Colorado, approximately 40 miles southwest of Meeker, Colorado, and 30 miles northwest of Rifle, Colorado. The area is bounded on the north and south by synclinal and anticlinal trends, and on the northeast by an anticlinal closure known as the Piceance Creek Dome.

(B) *Depth.* The average depth to the top of the Mesaverde formation is approximately 7200 feet.

(x) *Mancos formation to the base of the Mancos "B" in Colorado.*

(A) *Delineation of formation.* The Mancos formation to the base of the Mancos "B" is located in the Rio Blanco and Dry Gulch Units of Rio Blanco County, Colorado, approximately 40 miles southwest of Meeker, Colorado and 30 miles northwest of Rifle, Colorado. The area is bounded on the north and south by synclinal and anticlinal trends, and on the northeast by an anticlinal closure known as the Piceance Creek Dome.

(B) *Depth.* The average depth to the top of the Mancos formation is approximately 10,500 feet.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,087 Ceiling Prices; High-Cost Gas Produced From Tight Formations (Colorado-6)

45 F. R. 69930 (October 22, 1980).

18 CFR Part 271

[Docket No. Rm 79-76 (Colorado-6)]

Ceiling Prices; High-Cost Gas Produced From Tight Formations

AGENCY: Office of Pipeline and Producer Regulations, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendations of the Colorado Oil and Gas Conservation Commission that the Mancos "B" formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 14, 1980.

Public hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 30, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Streeet, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or Victor Zabel, (202) 357-8559.

I. Background

On October 3, 1980, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980) that the Mancos "B" formation underlying certain lands in the North Douglas Creek area in Rio Blanco County, Colorado, be designated in the Commission's regulations as a tight formation. The United States Geological Survey concurs in Colorado's recommendation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Mancos "B" formation be designated a tight formation should be adopted. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

The recommended formation is located in Rio Blanco County, Colorado and is appoximately 350 feet thick in the southern part, thinning to the north, and more silty to the east. The average depth to a producing interval is approximately 2500 feet.

II. Discussion of the Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed areas is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of crude oil per day.

Colorado further asserts that the typical casing design of wells drilled in the recommended formation, as required by Colorado's rules and regulations, will protect any fresh water aquifers in the area.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by the Commission in Order No. 97, issued August 1, 1980, in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Mancos "B" formation, as described and delineated in its recommendation, be designated a tight formation pursuant to § 271.703.

III. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 14, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Colorado—6), and should give reasons including any supporting data for any recommendation. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Commission no later than October 30, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703 is amended by adding new paragraphs (d)(1)(xi) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.*

(1) The following formations are designated as tight formations:

(i) through (x) [Reserved]

(xi) *Mancos "B" formation in Colorado.*

(A) *Delineation of formation.* The Mancos "B" formation is located in northwestern Colorado in the North Douglas Creek area in Rio Blanco County, about 10 miles south of the town of Rangely, Colorado, on the Douglas Creek Arch which separates the Uinta and Piceance Creek geologic basins.

(B) *Depth.* The average depth to the top of the Mancos "B" formation is approximately 2500 feet.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,088 Ceiling Prices; High-Cost Gas Produced From Tight Formations (New Mexico-1)

45 F. R. 69931 (October 22, 1980).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-1)]

Ceiling Prices; High-Cost Gas Produced From Tight Formation

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the New Mexico Oil Conservation Division that the Austin-Mississippian formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 17, 1980.

Public hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 31, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or Victor Zabel (202) 357-8559.

Issued October 16, 1980

I. Background

On October 9, 1980, the New Mexico Oil Conservation Division (New Mexico) submitted to the Commission, in accordance with § 271.703 of the Commission's Final Regulations (45 FR 56034, August 22, 1980), a recommendation that the Austin-Mississippian formation in Lea County, New Mexico, be designated in the Commission's regulations as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New Mexico's recommendation that the Austin-Mississippian formation be designated a tight formation should be adopted. The United States Geological Survey concurs with New Mexico's recommendation. New Mexico's recommendation and supporting data are on file with the Commission and are available for public inspection.

The recommendation formation is located in six townships contained entirely in Lea County, New Mexico (Townships 13, 14, and 15 South, Ranges 35 and 36 East, NMPM). The Austin-Mississippian formation contains approximately 138,240 contiguous acres and ranges from 200 to 300 feet in thickness. The average depth to the top of the recommended formation is 13,250 feet.

II. Discussion of the Recommendation

New Mexico claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by New

Mexico on this matter demonstrates that:

(1) The average *in-situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stablized production rate, against atmospheric pressure, of wells completed for production from the Austin-Mississippian formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of crude oil per day.

New Mexico further asserts that the typical casing design of wells drilled in the recommended formation, as required by New Mexico's rules and regulations, will protect fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by New Mexico that the Austin-Mississippian formation, as described and delineated in New Mexico's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

III. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426, on or before November 17, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (New Mexico—1), and should give reasons including any supporting data for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., 20426, during business hours.

Any persons wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Commission no later than October 31, 1980.

(Natural Gas Policy Act of 1978, U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event New Mexico's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703 is amended by adding new paragraphs (d)(1)(xii) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.*

(1) The following formations are designated as tight formations:

(i) through (xi) (Reserved)

(xii) *Austin-Mississippian formation in New Mexico.*

(A) *Delineation of formation.* The Austin-Mississippian formation is located entirely in Lea County, New Mexico. The area consists of 138,240 contiguous acres, located approximately 6 to 12 miles North of Lovington, New Mexico.

(B) *Depth.* The average depth to the top of the Austin-Mississippian formation is approximately 13,250 feet.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,089 Ceiling Prices; High-Cost Gas Produced From Tight Formations (Texas-3)

45 F. R. 71587 (October 29, 1980).

18 CFR Part 271

[Docket No. RM 79-76 (Texas-3)]

Ceiling Prices; High-Cost Gas Produced From Tight Formations

October 24, 1980.

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Texas Railroad Commission that the Cisco Sandstone formation be designated as a tight formation under § 271.703(d).

DATES: Comment date: Comments on the proposed rule are due on November 24, 1980.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 10, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or William Bushey, (202) 357-8590.

I. Background

On October 14, 1980, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Cisco Sandstone Formation located in the western part of the state of Texas be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Cisco Sandstone Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Cisco Sandstone Formation encountered in Section 72 in Reagan County, T. & P. R. Co. Block 2 Survey, Abstract 146, be designated as a tight formation. Reagan County is a part of Railroad Commission District No. 7C. The boundaries of Section 72 are as follows. The northern boundary of Section 72 is approximately 1.5 miles south of the Glasscock County line and the southern boundary is approximately 35.42 miles north of the Crockett County line. To the east, the boundary of Section 72 lies approximately 1.29 miles west of the Sterling County line and to the west, the boundary is approximately 27.8 miles east of the Upton County line. The Cisco Sandstone is located below the Wichita Formation and above the Canyon Formation. Currently, only one well is producing within the recommended formation. The well log shows the top of the Cisco Sandstone at an approximate

depth of 8,260 feet and the base located at approximately 8,288 feet, giving the formation a thickness of 28 feet.

III. Discussion of the Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing state and federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980 in docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Cisco Sandstone Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N. E., Washington, D. C. 20426, on or before November 24, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas-3), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise praticipate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than Novermber 10, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.*

(1) The following formations are designated as tight formations:

(i) through (xiii) [Reserved]

(xiv) *Cisco Sandstone Formation.*

(A) *Delineation of formation.* The Cisco Sandstone Formation is found in Reagan County, Texas.

(B) *Depth.* The top of the Cisco Sandstone Formation is located at an

approximate depth of 8,260 feet with an approximate thickness of 28 feet.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,090 Ceiling Prices; High-Cost Gas Produced From Tight Formations (Texas-4)

45 F. R. 71588 (October 29, 1980).

18 CFR Part 271

[Docket No. RM 79-76 (Texas-4)]

Ceiling Prices; High-Cost Gas Produced From Tight Formations

October 24, 1980.

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Texas Railroad Commission that the Vicksburg U-V Formation be designated as a tight formation under § 271.703(d).

DATES: Comment date: Comments on the proposed rule are due on November 24, 1980.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 10, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or William Bushey, (202) 357-8590.

I. Background

On October 14, 1980, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980) that the Vicksburg U-V Formation located in the southern part of the state of Texas be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Vicksburg U-V Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of the Recommendation

Texas recommends that the Vicksburg U-V Formation encountered in Hidalgo County, Santa Anita Survey, Abstract 63, McAllen Ranch (Vicksburg U-V, SE) Field, be designated as a tight formation. Hidalgo County is a part of Railroad District No. 4. The northern boundary line of the formation is approximately 10.42 miles south of the Brooks County line and the southern boundary lies approximately 14.92 miles south of the Brooks County line. The western and eastern boundaries of the recommended area are approximately 6.135 and 10.575 miles respectively, east of the Starr County line.

The Vicksburg U-V Formation is located below all other Vicksburg Sands except the Vicksburg Y, and the Vicksburg Group is located below the Frio Formation and above the Jackson Shale Formation. A typical induction log of the area shows the top of the Vicksburg U-V at an approximate depth of 12,305 feet, and extends to the Vicksburg Y. The base of the U-V Formation is at an approximate depth of

13,460 feet, resulting in an approximate thickness of 1,155 feet.

III. Discussion of the Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing state and federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Vicksburg U-V Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 24, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—4), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed.

An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 10, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.*

(1) The following formations are designated as tight formations:

(i) through (xiv) [Reserved]

(xv) *Vicksburg U-V Formation in Texas.*

(A) *Delineation of formation.* The Vicksburg Y Formation is found in Hidalgo County, Texas.

(B) *Depth.* The top of the Vicksburg U–V Formation in the McAllen Ranch Field is located at an approximate depth of 12,305 feet with an approximate thickness of 1,155 feet.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, and is also located in the official files of the jurisidictional agency which submitted the recommendation.

¶ 32,091 Ceiling Prices; High-Cost Gas Produced From Tight Formations (Texas-5)

45 F. R. 71589 (October 29, 1980).

18 CFR Part 271

[Docket RM 79-76 (Texas-5)]

Ceiling Prices; High-Cost Gas Produced From Tight Formations

October 24, 1980.

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Texas Railroad Commission that the Vicksburg Y Formation be designated as a tight formation under § 271.703(d).

DATES: Comment date: Comments on the proposed rule are due on November 24, 1980.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 10, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or William Bushey, (202) 357-8590.

I. Background

On October 14, 1980, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980) that the Vicksburg Y Formation located in the southern part of the state of Texas be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Vicksburg Y Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Vicksburg Y Formation encountered in Hidalgo County, Santa Anita Survey, Abstract 63, McAllen Ranch (Vicksburg Y) Field, be designated as a tight formation. Hidalgo County is a part of Railrad District No. 4. The northern boundary line of the recommended formation is approximately 10.42 miles south of the Brooks County line and the southern boundary is approximately 14.92 miles south of the Brooks County line. The western and eastern boundaries of the recommended area are approximately 6.135 and 10.575 miles respectively, east of the Starr County line.

The Vicksburg Y Formation is located below all other Vicksburg Sands and the Vicksburg Group is located below the Frio Formation and above the Jackson

Shale. A typical induction log of the area shows the top of the Vicksburg Y at an approximate depth of 13,595 feet in the north to 13,244 feet in the south, and the base is located at approximately 15,550 feet in the north to 14,961 feet in the south, giving the formation a thickness of 1,955 feet in the north and 1,717 feet in the south.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further assets that existing state and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Vicksburg Y Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 24, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—5), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed.

An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 10, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

1. Section 271.703(d) is amended by adding new subparagraphs (1) and (2) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.*

(1) The following formations are designated as tight formations:

(i) through (xv) [Reserved]

(xvi) *Vicksburg Y Formation in Texas.*

(A) *Delineation of formation.* The Vicksburg Y Formation is found in Hidalgo County, Texas.

(B) *Depth.* The top of the Vicksburg Y Formation in the McAllen Ranch Field is located at an approximate depth of 13,595 feet with an approximate thickness of 13,244 feet in the south and ranges in thickness from approximately 1,955 feet in the north to 1,717 feet in the south.

(2) A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, and is also located in the official files of the jurisdictional agency which submitted the recommendation.

¶ 32,092 High-Cost Gas Produced From Tight Formations (Colorado)

45 F. R. 72199 (October 31, 1980).

18 CFR Part 271

High-Cost Gas Produced From Tight Formations

AGENCY: Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Colorado Oil and Gas Conservation Commission that the Lower Mesaverde formation (consisting of the Rolling, Cozzette and Corcoran Sandstone members) be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 26, 1980.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 11, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299 or Victor Zabel (202) 357–8559.

October 27, 1980.

I. Background

On October 3, 1980, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980) that the Rollins, Cozzette and Corcoran sandstones underlying specified lands in Mesa County, Colorado be designated in the Commission's regulations as tight formations. On October 20, 1980, Colorado submitted a corrected recommendation redefining the recommended formation as the Lower Mesaverde formation (consisting of the Rollins, Cozzette and Corcoran Sandstone members). Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Lower Mesaverde formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

The recommended formation is located approximately 30 miles east-northeast of Grand Junction, Colorado and lies in the Plateau Creek Field area in Mesa County, Colorado. The average depth to the top of the producing interval is approximately 3,850 feet.

II. Discussion of the Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–7 convened by

Colorado on this matter demonstrates that;

(1) The average *in-situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the Lower Mesaverde formation (as defined), without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of crude oil per day.

Colorado further asserts that the typical casing design of wells drilled in the recommended formation, as required by Colorado's rules and regulations, will protect fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, Issued August 1, 1980, in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Lower Mesaverde formation (consisting of the Rollins, Cozzette, and Corcoran Sandstone members), as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

III. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before November 26, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Colorado-5), and should give reasons including any supporting data for any recommendations. Comments should also indicate any supporting data for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during business hours.

Any persons wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Commission no later than November 11, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding a new subparagraph (17) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designatd as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdicational agency that submitted the recommendation.

(1) * * *

(2) through (16) [Reserved]

(17) *The Lower Mesaverde Formation in Colorado*—(i) *Delineation of*

formation. The Lower Mesaverde Formation consisting of the Rollins, Cozzette and Corcoran Sandstone members, is located in the Plateau Creek Field area in Mesa County, Colorado. It is approximately 30 miles east northeast of Grand Junction, Colorado, and lies in the southern part of the Piceance Creek Basin. (Colorado–5).

(ii) *Depth.* The average depth to the Lower Mesaverde Formation is 3,850 feet.

¶ 32,093 High-Cost Gas Produced From Tight Formations; Ceiling Prices (Louisiana-1)

45 F. R. 72687 (November 3, 1980).

18 CFR Part 271

[Docket No. Rm 79-76 (Louisiana-1)]

High-Cost Gas Produced From Tight Formations; Ceiling Prices

AGENCY: Office of Pipeline and Producer Regulation. Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the State of Louisiana Office of Conservation that the Arkadelphia Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 28, 1980.

Public hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 12, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner (202) 357-8299 or William Bushey (202) 357-8590.

Issue: October 28, 1980

I. Background

On October 10, 1980, the State of Louisiana Office of Conservation (Louisiana) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Arkadelphia Formation, located in the northeast corner of the State of Louisiana be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Louisiana's recommendation that the Arkadelphia Formation be designated a tight formation should be adopted. Louisiana's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation lies entirely within Union Parish and is located in the northwest section of the Monroe Gas Field. The Arkadelphia Formation is defined as that formation occurring between the measured depths of 2038 feet and 2080 feet. Within the recommended area, the Arkadelphia varies in thickness from 30 to 60 feet, thinning from the northwest to the southeast.

III. Discussion of the Recommendation

Louisiana claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Louisiana on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section

of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Accordingly, Louisiana recommends that the Arkadelphia Formation be designated as a tight formation since it meets the requirements set forth above under § 271.703(c)(2)(i) of the regulations. Evidence presented to Louisiana also indicates that the Arkadelphia Formation would qualify under § 271.703(c)(2)(ii), since the evidence establishes that the price set forth in § 271.703(a) is necessary to provide reasonable incentives for production. In view of this, Louisiana is also recommending that the Arkadelphia Formation qualify under § 271.703(c)(2)(ii).

Louisiana further asserts that the spacing requirements of Statewide Order No. 29–B will assure that development of the Arkadelphia formation will not adversely affect any fresh aquifer that is or is expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980 in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Louisiana that the Arkadelphia formation, as described and delineated in Louisiana's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 27, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Louisiana—1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 12, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. sections 3310–3342).

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Louisiana's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

(1) Section 271.703(d) is amended by adding new subparagraph (18) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as

tight formations. A more detailed description of the geological extent and geological parameters of the designated tight formation is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

(1) * * *

(2) Through (17) [Reserved].

(18) *Arkadelphia formation in Louisiana.*

(i) *Delineation of formation.* The Arkadelphia Formation is found in Union Parish, Louisiana. RM79-76 (Louisiana—1).

(ii) *Depth.* The Arkadelphia Formation is defined as that formation occurring between the measured depts of 2038 feet and 2080 feet.

¶ 32,094 Eligibility, Rates and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities

45 F. R. 74924 (November 13, 1980); 45 F. R. 80308 (December 4, 1980)

18 CFR Part 292

[Docket No. RM 81-2]

Eligibility, Rates and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities; Notice of Proposed Rulemaking

Issued: November 6, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it proposes to adopt regulations implementing section 643 of the Energy Security Act. The Energy Security Act contains amendments to the Federal Power Act and the Public Utility Regulatory Policies Act concerning geothermal energy. The proposed regulations would permit utility-owned small power production facilities using geothermal resources as a primary energy source to obtain the rate and exemption benefits of section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The regulations also permit qualifying small power production facilities using geothermal resources of up to 80 megawatts capacity to obtain the exemption benefits of section 210 of PURPA.

DATES: Written Comments by December 15, 1980.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM 81-2).

FOR FURTHER INFORMATION CONTACT:
Adam Wenner, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033;
or
Glenn Berger, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Issued: November 6, 1980.

Background

On June 19, 1980, the Congress enacted section 643 of the Energy Security Act of 1980 (ESA),[1] which contains six amendments concerning geothermal energy to the Federal Power Act and the Public Utility Regulatory Policies Act of 1978 (PURPA). These proposed rules would implement four of those amendments.

Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA) mandates that the Federal Energy Regulatory Commission (Commission) prescribe rules under which small power production facilities and cogeneration facilities can obtain "qualifying" status, and thus become eligible for the rates and exemptions set forth in the commission's rules implementing section 201 of PURPA.

Section 201 of PURPA defines a "small power production facility" as a facility which:

(1) Produces electric energy soley by the use, as a primary energy source, of biomass, waste, renewable resouces, or any combination thereof; and

(2) Has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts.

A cogeneration facility is defined as a facility which produces electric energy and steam or form of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.

Thus cogeneration facilities produce sequentially two forms of useful energy, namely electric power and heat.

[1] Pub. L. No. 96-294, 94 Stat. 611 (1980).

Cogeneration facilities can use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. By using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's efforts to conserve its energy resources.

Small power production facilities as defined in the Act use biomass, waste, or renewable resouces, including wind, solar, geothermal or hydroelectric energy, to produce electric power. Reliance on these sources of energy can reduce the need to consume fossil fuels to generate electric power.

Prior to the enactment of PURPA, a congenerator or small power produced seeking establish interconnected operation with a utility faced three major obstacles. first, a utility was not generally willing to purchase the electric output at an attractive rate. Second, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Third, a cogenerator or small power producer that provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to puchase available electric energy from congeneration and small power production facilities that obtain qualifying status under section 201 of PURPPA, and to provide back-up power and other services to such facilities on a non-discriminatory basis. For such purchases, electric utilities are required to pay rates that are just and reasonable to the ratepayers of the utility, that are in the public interest, and that do not discriminate against cogenerators and small power produces.

Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulations regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I and sections 210–212 of Part II), and from the Public Utility Holding Company Act. However, the Commission can not extempt qualifying facilities from local, State, or Federal licensing, siting, or environmental laws or regulations. Finally, under section 206(c)(3) of the Natural Gas Policy Act of 1978 (NGPA), the Commission could exempt qualifying congeneration facilities from the incremental pricing program under Title II of the Natural Gas Policy Act of 1978 (NGPA).

The Commission issued proposed regulations implementing sections 201 and 210 in 1979. After a series of public hearings, analysis of the extensive written comments received, and consultation with State public utility regulatory commissions, final rules were issued under section 210 on February 19, 1980 [2] and Section 201 on March 13, 1980.[3] On October 23, 1980, the Commission issued a rule, subject to Congressional review, exempting mechanical cogeneration facilities from incremental pricing under Title of the NGPA.[4]

Section 643(a) of the Energy Security Act is intended to clarify the authority of the Federal Energy Regulatory Commission (FERC or Commission) to classify geothermal resources as a "primary energy source" for purpose of eligibility for use by a small power production facility under section 3(17)(A) of the Federal Power Act, as amended by section 201 of PURPA. The conference report indicates that the legislation does not intend "to cast the FERC's present regulations under section 3(17) into doubt by reason of this amendment."[5]

Section 643(b) of ESA contains three amendments to section 210 of PURPA.

[1] 45 Fed. Reg. 12214 (Feb. 25, 1980).

[2] 45 Fed. Reg. 17959 (March 20, 1980).

[3] Docket No. RM80-62, issued October 23, 1980, 45 Fed. Reg. ————, October —, 1980).

[5] S. Rep. No. 96-824, 96th Cong., 2nd Sess. 312 (1980). It is the Commissions's position that the geothermal facilities were eligible for qualificationas small power production facilities.

Subsection 643(b)(1) amends section 210(a) of PURPA. Section 210(a) requires the Commission to prescribe rules "as it determines necessary to encourage cogeneration and small power production . . . which rules [shall] require electric utilities to offer to sell electric energy to and purchase electric energy from qualifying cogeneration and small power production facilities." The amendment to this section adds "geothermal small power production facilities of not more than 80 megawatts capacity" to the list of technologies which the Commission must issue rules to encourage; but not to the class of energy-production facilities to and from which electric utilities are statutorily required to sell and purchase.

The requirement to purchase from and sell to cogeneration and small power production facilities appears to be extended only to "qualifying" facilities. The difference between a qualifying and non-qualifying cogeneration or small power production facility is that a "qualifying" facility must be owned by a person "not primarily engaged in the generation or sale of electric power [other than electric power solely from cogeneration and small power production facilities]."[6]

Utility-owned geothermal small power production facilities do not meet this requirement. Thus, it is not clear, on the face of the statute, that the Commission is authorized to require electric utilities to purchase from or sell to geothermal small power production facilities which are wholly owned by electric utilities, or that it can price their purchases according to the purchasing utility's "avoided costs."[7]

However, the legislative history of ESA indicates that it was the intent of Congress that the Commission, under the "broad authority of section 210 to encourage geothermal small power production," have the authority to make "some or all of the section 210 rate benefits applicable to such facilities in the same manner as such benefits are available to non-utility owned facilities."[8]

In Order No. 69, the Commission noted that section 210(a) of PURPA "provides a general mandate for the Commission to prescribe rules necessary to encourage cogeneration and small power production."[9] While the specific requirement that the Commission issue rules requiring electric utilities to offer to sell to and buy from cogeneration and small power production facilities is limited in sections 210(a)(1) and (2) to "qualifying" facilities, the legislative history and the Commission's interpretation of the general mandate to encourage cogeneration and small power production lead the Commission to believe that it has the authority to extend these privileges to utility-owned geothermal small power production facilities. Therefore, the Commission believes that it has the authority to require electric utilities to purchase from and sell to utility-owned geothermal small power production facilities, and to price these purchases on an avoided cost basis.

Section 643(b)(2) of ESA amends sections 210(e)(1) of PURPA to authorize the Commission to exempt "geothermal small power production facilities of not more than 80 megawatts capacity" from the Federal Power Act, the Public Utility Holding Company Act, and State laws and regulations respecting the rates or the financial or organizational regulation of electric utilities, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. The Commission's exemptive authority under this amendment is not limited to "qualifying" geothermal small power production facilities. As a result, the

[6] This view is based on the legislative history of PURPA. 124 Cong. Rec. S. 17806 (daily ed. October 9, 1978) (remarks of Senators Durkin and Jackson).

[7] Sections 3(17)(C)(ii) and 3(18)(B)(ii), Federal Power Act, 18 C.F.R. § 292.206.

[8] "Avoided costs" are defined in § 292.101(b)(6) of the Commission's rules as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

[9] 126 Cong. Rec. S. 7423 (daily ed. June 26, 1980) (remarks of Sen. McClure). 126 Cong. Rec. H5718, 5724 (daily ed. June 28, 1980) (remarks of Reps. Dingell, Sharp).

[10] 45 Fed. Reg. 12214, 12221 (Feb. 25, 1980).

Commission may exempt utility-owned geothermal small power production facilities from these laws and regulations.

Finally, section 210(e)(2) of PURPA limited the Commission's authority to exempt qualifying small power production facilities to those with a capacity of 30 megawatts of less.[10] Section 643(b)(3) of ESA increases the limit of "80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source . . ." Thus, the Commission may exempt any "qualifying" small power production facility using geothermal energy as the primary energy source from the laws and regulations specified in section 210(e)(1) of PURPA.

Summary of the Proposed Rules

§ 292.204 Primary energy source.

Section 3(17)(A) of the Federal Power Act, as amended by section 201 of PURPA, defines a "small power production facility" as a facility which produces energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts. The amendment contained in section 643(a)(1) of ESA states that geothermal resources are an eligible primary energy source for small power production facilities.

Section 292.204 of the Commission's rules sets forth criteria for qualifying small power production facilities. To reflect section 643(a)(1) of ESA, the Commission proposes to amend this section of its rules to make it clear that small power producton facilities using geothermal resources as a primary energy source can be qualifying facilities. This change appears in § 292.240(b)(1)(i), where "geothermal resources" is added to the list setting forth the eligible primary energy sources of a qualifying small power production facility.

Definitions

§ 292.202 "Utility geothermal small power production facility."

The Commission proposes to amend § 292.202 by adding a new paragraph (o) which defines "utility geothermal small power production facility" (UGC) as a small power production facility which uses geothermal energy as the primary energy source, and of which an electric utility or electric holding company, or any combination thereof, owns more than 50 percent of the outstanding voting securities.[11]

§ 292.101 "Qualifying facility."

Section 292.101(b)(1) would include a "utility geothermal small power production facility" within the definition of "qualifying facility" set forth in the Commission's rules. This inclusion would make utility geothermal small power production facilities eligible for all of the rate and exemption benefits provided for non-utility owned cogeneration and small power production facilities.[12]

[10]Small power production facilities between 30 and 80 megawatts which use biomass as a primary energy source are exempt from the Public Utility Holding Company Act, and from State regulation of wholesale rates and financial organization. See § 292.602 of the Commission's rules.

[11]Section 292.206 presently permits cogeneration and small power production facilities of which utilities own up to 50 percent of the equity to be qualifying facilities. For purposes of this discussion, a geothermal company of which electric utilities own more than 50 percent of the equity or voting securities is considered to be "wholly-utility owned," and is referred to as a utility geothermal company" or UGC.

[12]In light of the previously discussed legislative history, it may appear to be inconsistent to classify utility-owned geothermal facilities as "qualifying facilities." One result of that legislation is to permit the Commission to treat utility-owned geothermal facilities the same way as non-utility owned facilities. The Commission rules on cogeneration and small power production are replete with references to "qualifying facilities"; as a drafting matter, rather than revising virtually every rule to include utility-owned facilities, it is less confusing to include UGC's within the definition of qualifying facilities.

In proposing these changes, the Commission is attempting to make available to the utility industry the same benefits for geothermal projects that are provided to non-utility owned cogeneration and small power production facilities. As indicated in the following discussion, the Commission recognizes that, in certain respects, utilities participating in alternative energy development do face different risks and opportunities than does the non-regulated sector. It seeks comment on the specific proposals set forth in these rules, and on the general issues raised in these discussions.

§ 292.601 Exemption of qualifying facilities from the Federal Power Act.

Non-Utility Owned Facilities

Section 643(b)(3) of ESA amends section 210(e)(2) of PURPA by permitting the Commission to exempt qualifying small power production facilities of up to 80 megawatts capacity using geothermal resources from regulation under the Federal Power Act, the Public Utility Holding Company Act, and from State laws and regulations respecting rates or the financial or organizational regulation of electric utilities.

Section 292.601 of the Commission's rules sets forth exemptions of qualifying facilities from provisions of the Federal Power Act. This rule presently exempts qualifying small power production facilities of 30 megawatts or less from certain provisions of the Federal Power Act. The Commission proposes to amend this section to exempt qualifying small power production facilities using geothermal energy to the maximum extent permitted under ESA. This would be accomplished by amending § 292.601, to provide that exemption from the Federal Power Act applies to all qualifying facilities, other than small power production facilities with a capacity which exceeds 30 megawatts, and which use a primary energy resource other than geothermal resources.

Utility-Owned Facilities—Rate Regulation of Sales to Parent Utilities

As discussed previously, the legislative history of section 643(b) of the ESA indicates that the Commission may provide some or all of the section 210 rate benefits to utiltiy-owned geothermal facilities in the same manner as such benefits are available to qualifying (*i.e.*, non-utility-owned) facilities.

Regulated Transactions

In most instances, if no exemption from the Federal Power Act were provided, sales of power by a UGC subsidiary to its utility parent would be sales for resale in interstate commerce, and would be subject to Commission regulation under Part II of the Federal Power Act. Sections 205 and 206 of the FPA provide that rates shall be just and reasonable; the Commission has interpreted these sections to mean that, in general, rates should be based on the cost of providing service, including operating costs and a reasonable return on investment. Unlike non-utility small power producers and cogenerators, utility parent companies, and their UGC subsidiaries are, for the most part, already subject to public disclosure and scrutiny of their costs. The use of cost-of-service pricing should not be a disincentive to these types of transactions—at least not to the same extent that it would be to non-utility companies.

Approval by this Commission of rates for transactions between a UGC subsidiary and its parent may be viewed favorably by the institutions which might finance the UGC. This is so because, if this Commission approves the rates, the utility has reasonable assurance that neither the States nor this Commission will challenge (or permit challenge) to the pass through of the purchased power costs in retail and wholesale rates.[13]

In addition, in the event that the UGC facility does not perform up to

[13] *See, e.g.*, Narragansett Electric Company v. Burke *et al.*, 2431 A.2d 1358, cert. denied 435 U.S. 972 (1977). The Federal Power Commission had established a rate for sales of power from New England Power Company (NEPCO) to Narragansett Electric Company (Narragansett). The Rhode Island

expectations, regulation of a sale from the UGC to its parent under the FPA may provide greater assurance of cost recovery. There are several avenues by which a jurisdictional utility might recover its investment in a geothermal project. The Commission has allowed the recovery of costs through amortization for plants which did not become operational.[14] A geothermal facility may qualify for treatment as research, development and demonstration expenses (RD&D) under Commission Order No. 556.[15] If it does, the expenses associated with the project would be included within the utility's cost of service, and passed through to the ratepayer, regardless of its actual operation.[16]

Thus, in the case of a regulated sale from a UGC subsidiary to its utility parent, there is significant assurance of recovery of expenditures. The return on investment to the UGC will, on the other hand, be regulated, and will be limited to a level which the Commission determines to be just and reasonable. As will be discussed later, in the case of an unregulated sale, a UGC would take greater risks of non-recovery of costs, but would have the opportunity to receive a greater return on its investment.[17]

Exempt Transactions—Sales From UGC Subsidiary to Its Parent Company

If the Commission were to exempt UGC's from the Federal Power Act, the rate for purchases of power by the parent from its UGC subsidiary would not be established under the just and reasonable standards of section 205 or 206 of the FPA. Instead it would be based on the pricing provisions set forth in § 292.101—§ 292.306 of the Commission's rules. These rules establish a right for a qualifying facility to receive rates based on the "avoided costs" of the purchasing utility, in the case of purchases from "new capacity."[18] For purchasers from existing capacity, the State regulatory authority or nonregulated electric utility may establish rates lower than avoided cost levels, if it finds that the lower rate is "sufficient to encourage cogeneration and small power production."[19]

Finally, the rules provide that rates or terms established by agreement between an electric utility and a qualifying facility do not violate the Commission's rules under section 210 of PURPA, even if they differ from the avoided cost principles established in the rules.[20] This section permits parties to use negotiated rates and terms, rather

Public Utilities Commission (PUC) investigated the costs underlying the wholesale rate and attempted to prevent Narragansett from passing through some of the purchased power expenses to its retail customers. The Rhode Island Supreme Court held that the PUC lacks jurisdiction to inquire into the reasonableness of NEPCO's wholesale rate because the Federal Power Act gave sole jurisdiction over sales for resale in interstate commerce to the Federal Power Commission. The Supreme Court had earlier held that regulation over the transmission and sale of electric energy at wholesale in interstate commerce is not within the authority of the States. Connecticut Light and Power Co. v. FPC, 324 U.S. 515 (1945), Public Service Commission of Rhode Island v. Attleboro Steam and Electric, 273 U.S. 83 (1927).

[14] Order No. 49, New England Power Company, Docket Nos. ER76-304, ER76-317, El276-498, issued July 19, 1979.

[15] Order Prescribing Changes in Accounting and Rate Treatment for Research, Development and Demonstration Expenditures, Docket No. RM76-17, issued June 3, 1977.

[16] See *id., mimeo* at 7. In such instances, however, any revenue obtained from successful operation of the facility must similarly be credited to the ratepayer.

[17] The relationship between risk-taking and opportunity for profit is discussed in the Conference Report accompanying PURPA. The conferees recognized that "cogenerators and small power producers are different from electric utilities, not being guaranteed a rate of return on their activities generally or on the activities vis a vis the sale of power to the utility and where risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable." Conference Report in H.R. 4018, Public Utility Regulatory Policies Act of 1978, H.R. Rept. No. 1750, 97, 95th Cong., 2d Sess. (1978).

[18] See n. 7, *supra*. "New capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978 (§ 292.304(b)(1)).

[19] § 292.304(b)(3).

[20] § 292.301(b)(1).

than State-established rates, for purchases. However, this provision does not divest a State regulatory authority, or this Commission, of its authority to review contracts for purchases as part of its regulation of the purchasing electric utility.[21]

Accordingly, if the Commission exempted UGC's from the FPA, the rate would be established according to the principles described above. For purposes of this discussion, it is assumed that an avoided cost rate is higher than a rate which is "just and reasonable" on the basis of the selling utility's cost of service. This may not always be a valid assumption. On the one hand, the avoided cost rates established by a State regulatory authority or non-regulated electric utility may exceed the delivered cost of power from a geothermal facility.

On the other hand, by definition, a utility's "avoided costs" are "the incremental costs . . . of electric energy or capacity which, but for the purchase from the qualifying facility . . . such utility would generate itself or purchase from another source." A statutory limitation on the rate that utilities can be compelled to pay for power from cogeneration and small power production facilities is that the rate must be "just and reasonable to the electric consumers of the electric utility and in the public interest."[22]

The Conference Report indicates that this requirement is "to be interpreted in a manner which "looks to protecting the interest of the electric consumer in receiving electric energy at equitable rates."[23]

In establishing the full avoided cost pricing standard, the Commission was cognizant of the need to avoid ratepayer subsidies to cogenerators and small power producers, observing that, under that standard, "the utilities' customers are kept whole, and pay the same rate as they would have paid had the utility not purchased energy and capacity from the qualifying facility."[24]

It appears to the Commission that, in most cases, if the geothermal facility is the lowest-cost power supply alternative, the parent utility's avoided costs should be calculated on the basis of the cost of the geothermal facility. There may, however, be instances in which the avoided cost rates established by the State regulatory authority are higher than these costs. In such cases, the rates paid by a parent utility to its UGC subsidiary would be the same as the rates that are available to non-affiliated cogenerators and small power producers. If the rates established by the State regulatory authority fall within the previously discussed statutory parameters, the Commission does not believe that use of these rates for transactions between affiliated companies will be troublesome.

The receipt by the UGC of such avoided costs, rather than cost-of-service based rates, will not benefit the parent utility company unless the parent is permitted to flow through to its customers these purchased power expenses. That issue will be determined by the regulatory authorities which establish rates for sales by the parent utility. For sales for resale in interstate commerce, the FERC makes that determination; for retail sales, the State regulatory authorities could determine whether they should be included in the cost of service and passed through to the ratepayers. In contrast to the holding in *Narragansett, supra*, in the case of an unregulated sale, there would be no Federal imprimatur on the expenditure for the purchase by the parent from the UGC subsidiary. As a result, a State commission might refuse to permit the pass-through of some or all of the parent utility's purchased power costs from its UGC subsidiary. The investment community may regard the lack of Federal assurance of cost recovery as

[21] 45 Fed. Reg. 12214, 12233 (Feb. 25, 1980).

[22] Section 210(b)(1) of PURPA.

[23] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 97, 95th Cong., 2d. Sess. (1978).

[24] 45 Fed. Reg. 12214, 12222 (Feb. 25, 1980).

increasing the risk associated with the project. In that case, the costs of financing the project would increase.

Moreover, in an unregulated transaction, in the case of failure of the UGC, there would be no provision for the recovery of costs through amortization, as in the procedure for regulated sales under the precedent cited above. In most instances, if a purchasing utility fails to receive power, it will not be able to avoid costs. The avoided cost payment to the UGC in such a case would be zero. Since the costs of the UGC are not a part of the business of regulated parent company, they would be borne by the stockholders, rather than the ratepayers.[28]

Conversely, in the case of a successful project, the unregulated UGC subsidiary could receive a greater profit than it would otherwise have obtained. In sum, as a reward for taking the risk that expenses may not be recovered, the UGC would have the opportunity to retain the benefits of its venture.

In order to accommodate utilities which prefer to have their utility geothermal subsidiaries regulated under the Federal Power Act, the Commission proposes in § 292.601(d) to allow a UGC to elect such regulation. Section 292.601(d) states that upon request of a utility geothermal small power production facility the exemption from the Federal Power Act set forth in § 292.601(c) shall not apply.

Purchases by Nonaffiliated Utilities—Obligation To Purchase

The previous discussion was premised on a transaction between a UGC subsidiary and its parent utility. As stated previously, the legislative history of ESA indicates that the Commission has the authority to compel electric utilities to purchase electric power produced by UGC's. Under this provision, one utility might be required to purchase the output of another, unaffiliated utility's geothermal facility, and to pay avoided cost rates for such power.

This type of transaction raises an issue that was not raised in transactions between affiliated companies. Transactions between a parent and subsidiary can be assumed to be voluntary, as they are between companies ultimately controlled by the same persons. Transactions between non-affiliated companies, however, might not be voluntary. A utility might construct a geothermal facility and, under the authority provided in § 292.303 of the Commission's rules, compel another utility to purchase the energy and capacity of the geothermal facility.

In most instances, transactions between utilities under the FPA are voluntary. Permitting UGC's to compel other utilities to purchase their power would be a deviation from these principles.

Avoided Cost Pricing

With regard to the pricing of purchases from UGC's, it is probable that use of avoided-cost pricing would provide for greater development of geothermal resources than would occur if cost-of-service pricing were used. Conversely, in cases where the cost of power from the UGC is less than the avoided cost, the ratepayers of the purchasing utility will not benefit from these lower costs. The Commission seeks comment on the appropriateness of avoided cost pricing for transactions between UGC's and non-affiliated utilities, and the ramifications for the affected utilities' ratepayers.

The Commission perceives the potential for *de facto* exclusion of competition resulting from sales between utilities and their geothermal subsidiaries. It has not, however, determined that this potential limitation

[28] *See, e.g.*, Opinion No. 7, in which the Commission concurred with the holding by the Federal Power Commission that ". . . a utility should be regulated on the basis of its being an independent entity: that is, a utility should be considered as nearly as possible on its own merits and not on those of its affiliates. (47 FPC at 363)." Opinion and Order Approving in Part and Modifying in Part Decision of Administrative Law Judge, Kentucky West Virginia Gas Company, Docket No. RP73-97 issued February 16, 1978, *mimeo* at 11.

on competition is a sufficient basis to deny exemption for this type of transaction. The Commission is particularly interested in obtaining comment on this point.

Obligations To Sell to Qualifying Facilities

The preceding discussion was directed to the obligation of electric utilities to purchase power from UGC "qualifying facilities." The Commission's rules also require, subject to certain restrictions, electric utilities "to sell energy and capacity requested by a qualifying facility." [26] With regard to UGC's, the Commission interprets this requirement to require only that an electric utility provide power required by the geothermal facility itself. The parent of the UGC could not use this provision to compel another electric utility to provide power to the parent's entire system.

§ 292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

Non-utility-Owned Facilties

The Commission similarly proposes to exempt "qualifying geothermal facilities" from the Public Utility Holding Company Act, and from State laws regarding rates of electric utilities and their financial and organizational regulation.

The Commission believes that exemption from these laws is necessary to encourage small power production using geothermal energy. The Commission is aware of no reason to distinguish between geothermal facilities smaller than 30 megawatts and those larger than that size but under 80 megawatts—the statutory maximum—for purposes of providing these exemptions. As noted previously, the Commission proposes to amend § 292.601(a) to apply both to utility-owned and non-utility owned small power production facilities using geothermal resources as a primary energy source. In the existing rules, the applicability of § 292.602 includes those facilities described in § 292.601(a). Therefore, exemption of both utility-owned and non-utility owned facilities from the Public Utility Holding Company Act is accomplished by the change in § 292.601(a) described above.

Utility-Owned Facilities

As noted previously, section 643(b)((2) of ESA amends section 210(e)(1) of PURPA to authorize the Commission to exempt "geothermal small power production facilities of not more than 80 megawatts capacity" from the laws and regulations specified in section 210(e)(1) As discussed previously, the geothermal facilities included in this provision are not limited to "qualifying" facilities—that is, they are not limited to facilities "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)." Thus, the Commission has the authority to exempt geothermal facilities of 80 megawatts or less that are up to 100 percent utility-owned from the Federal Power Act from the Public Utility Holding Company Act, and from State laws or regulations respecting utility wholesale rate and financial organization regulation.

Rather than directly owning a geothermal facility, utilities sometimes find it advantageous to organize a separate corporation or partnership to own a geothermal facility. The principal advantage of this form of ownership is the ability to utilize "project financing" by the entity organized to build or acquire the generating facility. The advantages of this form of organization were described by the Securities and Exchange Commission recently:

> This permits the sponsoring utilities to finance the facility through issuance of long-term securities [by the entity organized to acquire or build the facility] that are not subject to the mortgage bond indentures of the sponsoring companies. It also provides flexibility with respect to the kind of security

[26] § 292.303(b).

issued and the amount of debt used to finance the project. In addition, [for jointly-owned projects] the proportionate interests of the participants in the new facility can be altered as load forecasts change and new participants in the project can be admitted by a transfer of the voting securities, which avoids the delay and expense of obtaining a release under a sponsoring utility's indenture, a step that is always necessary in cases involving the transfer of an undivided ownership interest.[27]

An added advantage which is especially important in the development of an experimental and relatively high-risk technology such as geothermal generation is the ability of a sponsoring utility company to insulate itself from the consequences of a default on the obligations issued to finance the geothermal facility under the cross-default provisions in the sponsoring utilities' own mortgage.

To obtain these advantages, a utility or group of utilities considering addition of a geothermal facility might seek to establish a separate subsidiary corporation which owns the facility. However, if a utility company acquires 10 percent or more of the voting securities of a separate company established to construct or operate a geothermal facility, it may become a "public utility holding company" within the meaning of section 2(a)(7)(A) of the Public Utility Holding Company Act [28] (Holding Company Act or PUHCA). In addition, the acquisition of the voting securities of a company which owns a geothermal small power production facility may require approval from the Securities and Exchange Commission under sections 9 and 10 of PUHCA, if the acquiring company is an "affiliate," within the meaning of section 2(a)(11)(A) of PUHCA, of another public utility company.

Many utility companies, especially those that are currently organized only as operating companies, are reluctant to undertake an activity which would subject them to regulation as holding companies. This reluctance may make infeasible the use of the subsidiary form of corporate organization which is necessary for project financing.

The authority granted the Commission by section 643(b)(2) of ESA can remove these disincentives. Regulation under PUHCA is triggered by the acquisiton and ownership of the voting securities of an "electric utility company," defined generally in section 2(a)(3) of PUHCA. Thus, if a UGC is exempt from classification as an "electric utility company", the parent company would not require SEC approval for the acquisition of voting securities of a UGC (unless such parent company were a registered holding company under the PURPA, or a subsidiary of such holding company) and would not become a holding company as a result of that acquisition.

Effect on SEC Regulation

In proposed rules recently issued by the SEC, that Commission also observed that some utilities find it useful to establish separate subsidiary companies which own or operate generating plants to supply power to the sponsoring utilities. As noted by the SEC, the acquisition of the voting securities of this type of generating company permits the sponsoring company to secure a source of supply to serve existing or future needs. It does not enlarge the service area of an electric utility company, nor frustrate effective local regulation.[29]

The SEC noted further that some electric utilities may be deterred from ownership of generating subsidiaries because of their reluctance to become holding companies, or because of the need for case-by-case approvals of the acquisition of voting securities of a separate generating company under sections 9(a)(2) and 10 of PUHCA.

To remove these disincentives, the SEC proposed rules which would exempt electric utilities from obtaining approval for the acquisition of securities of such affiliate generating companies,

[27] Holding Company Act Release No. 21661, July 22, 1980, 45 FR 49954 (July 28, 1980).
[28] 15 U.S.C. § 701b(a)(7)(A).
[29] Holding Company Act Release No. 21661, n. 7, *supra*.

and which would classify a sponsoring utility company as an "exempt" holding company with respect to one or more eligible generating subsidiaries.

The grant of exemption would, however, require: (1) authorization to acquire voting securities by "the regulatory authorities having jurisdiction over the rates and service" of the parent utility; (2) the subsidiary generating company to supply all of the electricity it generates to its parent company or companies (with certain noted exceptions); and (3) that the issuance of securities by the generating company be "expressly authorized by a regulatory authority having jurisdiction over its rates and service."[30]

As indicated, the exemption under section 210(e) of PURPA eliminates the basis for the SEC's jurisdiction over the acquisition and ownership of "qualifying" facilities or UGC's. By excluding a UGC from the definition of "electric utility company" under section 2(a)(3) of PUHCA, the FERC's proposed rules would eliminate the SEC's jurisdiction under section 9(a)(2) of PUHCA, thus rendering moot the exemption available under the SEC's proposed Rules 14 and 15, as it would pertain to geothermal facilities of 80 megawatts capacity or less.[31]

Environmental Considerations

The Commission issued in June 1980, a draft environmental impact statement (DEIS) on rulemakings implementing sections 201 and 210 of PURPA. In the DEIS the Commission determined that PURPA-induced development of geothermal small power production facilities would not create significant environmental effects. In compliance with the National Environmental Policy Act of 1969 (NEPA), the Commission is examining the environmental effects associated with these rules.

Written Comments

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N. E., Washington, D. C. 20426. Comments should refer to Docket No. RM81-2 on the outside of the envelope and on all documents submitted to the Commission.

In order that the Commission be able to take into account as many comments as possible, the Commission requests that persons submitting comments assist in two ways. First, persons should identify specifically the section or subpart they are addressing. Secondly, where comments urge a different approach from one presented, specific alternative language should be proposed to the extent practicable.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission by December 15, 1980, will be considered prior to the promulgation of final regulations.

(Energy Security Act, Pub. L. No. 96-294, 94 Stat. 611 (1980), Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, 12009, 42 FR 46267)

In consideration of the foregoing, it is proposed to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 292.204 is amended by revising paragraph (b) to read as follows:

§ 292.204 Criteria for qualifying small power production facilities.

* * * * *

(b) *Fuel Use.* (1)(i) The primary energy source of the facility must be biomass,

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[30] *Id.* The exemptions are intended to facilitate joint ownership of conventional base-load generation plants, but have broader application.

[31] This approach is similar to the exemption from PUHCA contained in section 9 of the Pacific Northwest Electric Power Planning and Conservation Act (S. 885), which would exempt a "generating company" from the definition of an electric utility company in PUHCA. the SEC has indicated its support, in principle, for that exemption.

waste, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources.

2. Section 292.202 is amended by adding a new paragraph (o), to read as follows:

§ 292.202 Definitions.

* * * * *

(o) "Utility geothermal small power production facility" means a small power production facility which uses geothermal energy as the primary energy resource, and of which an electric utility or electric utility holding company, or any combination thereof, owns more than 50 percent of the outstanding voting securities.

3. Section 292.101 is amended by revising paragraph (b)(1) to read as follows:

§ 292.101 Definitions.

* * * * *

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or small power production facility which is a qualifying facility, or a utility geothermal small power production facility, under Subpart B of this part of the Commission's regulations.

* * * * *

4. Section 292.601 is revised to read as follows:

§ 292.601 Exemption of qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to qualifying facilities, other than those described in paragraph (b).

(b) *Exclusion.* This section does not apply to a small power production facility with a power production capacity which exceeds 30 megawatts if such facility uses any primary energy source other than geothermal resources.

(c) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 1–18, and 21–30;

(2) Sections 202(c), 210, 211, and 212;

(3) Section 305(c); and

(4) Any necessary enforcement provision of part III with regard to the sections listed in paragraphs (c)(1), (2) and (3) of this section.

(d) Upon request of a utility geothermal small power production facility, the exemption set forth in paragraph (c) shall not apply.

¶ 32,095 Preservation of Records of Public Utilities, Licensees, and Natural Gas Companies

45 F. R. 76696 (November 20, 1980).

18 CFR Parts 125 and 225

[Docket No. RM81-4]

Proposed Rulemaking To Amend Regulations To Govern the Preservation of Records of Public Utilities, Licensees, and Natural Gas Companies

November 13, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission is proposing to amend its regulations governing the Preservation of Records of Public Utilities and Licensees (18 CFR Part 125), and the Preservation of Records of Natural Gas Companies (18 CFR Part 225). The amendments would update the regulations to include clarifications, changes in requirements resulting from new legislation and certain other technical changes.

DATE: Comments are due December 15, 1980.

ADDRESS: Comments on this notice should be addressed to the Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM81-4.

FOR FURTHER INFORMATION CONTACT:
Elaine M. Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 3405N, Washington, D.C. 20426, (202) 357-9190
Joseph M. Harkins, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 3407N, Washington, D.C. 20426, (202) 357-9185

I. Background

Pursuant to its authority under sections 301, 304 and 309 of the Federal Power Act (16 U.S.C. 792-828c) and under sections 8, 10 and 16 of the Natural Gas Act (15 U.S.C. 717-717w) the Federal Energy Regulatory Commission (Commission) is proposing to revise its regulations concerning the Preservation of Records of Public Utilities and Licensees (18 CFR Part 125) and the Preservation of Records of Natural Gas Companies (18 CFR Part 225). These regulations apply to all books of account and other records prepared by, or on behalf of, public utilities or licensees (Part 125), or natural gas companies (Part 225).

Parts 125 and 225 were last revised on March 14, 1972 (Order No. 450, Docket No. R-429, 37 FR 6293, March 28, 1972). Since that time, the Commission has received a number of requests from companies required to file under these parts to make the following changes: (1) Clarify reporting instructions and record retention requirements; (2) change certain requirements and record retention periods as a result of advances in microfilm technology, or because the filing companies have found difficulty in complying with the present regulations; and (3) establish guidelines with respect to continuing plant inventory records. Certain additions are also proposed as a result of new reporting requirements under section 133 of the Public Utility Regulatory Policies Act (PURPA) (16 U.S.C. 2601-2645) and sections 105, 106(b) and 109 of the Natural Gas Policy Act (NGPA) (15 U.S.C. 3301-3432).

In order to aid the Commission in its determination of whether to implement the proposed changes, the Commission specifically invites comments on the following questions:

1. (a) Do the proposed revisions to the regulations governing preservation of records affect any Commission or State regulatory functions?

(b) Would State agencies now using current Parts 125 and 225 requirements in the exercise of their own regulatory responsibilities revise their regulations concurrently?

2. What is the estimated burden, in dollars, or hours, or both, associated with the current and the proposed Commission record retention requirements imposed upon companies which are subject to the requirements?

II. Summary of Proposed Revisions

The following is a brief summary of the Commission's proposed revisions to 18 C.F.R. Parts 125 and 225:

1. Amendments to the General Instructions (§§ 125.2 and 225.2): (a) Revise §§ 125.2(d)(3) and 225.2(d)(3), Figure 1, "Record Media" at Item No. 3.a., in "Record media/form", by identifying "COM" as Computer Output Microfilm, and in "Comments and Standards," by referencing the latest American National Standards Institute, Inc. (ANSI) standards: #PH 1.28–76 and #PH 1.41—1976 (Specifications for Photographic Film for Archival Records, Silver Gelatin Type on Polyester Base).

(b) Clarify instructions at §§ 125.2(e)(1) and 225.2(e)(1) with reference to microfilm certification by providing separate certification instructions for COM. A certification statement from the official validating or confirming the data could be retained separately from the microform series. Only the initials of the official and the date of the confirmation or validation would be required in the title or heading of each microfiche or record series jacket. A clear and standard microform notation which indicates the completion of the series and dates would be required at the close of each COM microform series.

Another change to the instructions at §§ 125.2(e)(1) and 225(e)(1) would be to add "series" after "record", in the first line.

(c) Add a sentence to §§ 125.2(e)(2)(ii) and 225.2(e)(ii) to provide for the attachment of microfilm retakes at the end of a reel, under certain conditions.

(d) Redesignate paragraph (j) in §§ 125.2 and 225.2 as subparagraph (j)(1), and add subparagraph (2) to provide guidelines for continuing plant inventory records. These records would be required of public utilities and natural gas companies pursuant to the Commissions's Uniform System of Accounts (see 18 C.F.R. Part 101 at Electric Plant Instructions, 11.C., and 18 C.F.R. Part 104 at Electric Plant Instructions, 13.A. (public utilities); and 18 C.F.R. Part 201, at Gas Plant Instructions, 11.C., and 18 C.F.R. Part 204 at Gas Plant Instructions (gas companies)). The records would be classified to show the quantity and costs of the various record or retirement units.

In order to provide an inventory of property units which can be "spot-checked" for proof of physical existence, a comparison of costs with such units to insure accurate accounting for retirements, and additional and retirement data for use in depreciation studies, the foillowing data would be required in the records: (1) The name of the item and the manufacturer's code number or, if built by the utility, engineering studies and details of the materials used; (2) the location of the unit and the department responsible for it; (3) the date an item was acquired or transferred to plant-in-service; (4) the cost of the item; (5) estimates of the item's service life and salvage value; (6) details of depreciation accounting for the item, such as monthly and yearly percentage rates and actual dollar deductions; all additions, modifications and retirements; accumulated depreciation amounts and information as to whether depreciation is calculated on a unit or group basis; and (7) the asset control account to which plant costs are charged.

2. Amendments to the Schedule of Records and Periods of Retention for Electric Utilities only (§ 125.3): (a) Amend Item No.22.1(e) for clarification purposes, by providing for the inclusion of "clearance logs with supporting data" with "Station and system generation reports." The clearance logs would indicate when equipment is in service and out of service.

(b) Amend Item Nos. 22.2(e) through (1) by changing the retention period for various records under the nuclear production section from "Life of corporation" to "10 years after plant is

retired." The change would make the retention periods consistent with other commission records retention provisions.

3. Amendments to the Schedule of Records and Periods of Retention (§§ 125.3 and 225.3):

(a) Apply footnote No. 5 to Item No. 39, "Records of accumulated provisions for depreciation and depletion of utility plant." Footnote no. 5 is a reference to paragraph (n)(5) in §§ 125.2 and 225.2. This paragraph provides that life and mortality study data for depreciation purposes shall be retained for the life of the corporation. These plant and depreciation records would, therefore, be retained for the life of the corporation for use in company mortality studies.

(b) Amend Item 40(b) to clarify that all bids and proposals evidencing a procurement must be retained by the company (*i.e.*, those which are both "accepted and nonaccepted").

(c) Add to Item No. 65, "Reports to Federal and State Regulatory Commissions," a requirement to retain Cost of Service Reports, required under section 133 of PURPA (§ 125.3), and reports for first sales of natural gas under sections 105, 106(b) and 109 of the NGPA § 225.3).

III. Written Comment Procedures

Interested persons wishing to comment on this proposal should submit their comments to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE, Washington, D.C. 20426 and should refer to Docket No. RM81-4. An original and 14 copies should be filed. All comments received prior to 4:30 p.m., December 15, 1980, will be considered by the Commission prior to promulgation of final regulations.

All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection during regular business hours in the Commission's division of Public Information, Room 1000, 825 North Capitol Street, NE, Washington, D.C. 20426.

(Natural Gas Act, is amended, 15 U.S.C. 717–717w; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Federal Power Act, as amended, 16 U.S.C. 792–828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; Department of Energy Organization Act, 42 U.S.C. 7107–7352; E.O. 12009 42 FR 46267)

In consideration of the foregoing, the Commission proposes to revise Part 125 of Subchapter C, and Part 225 of Subchapter F, Chapter I, Title 18 of the code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 125—PRESERVATION OF RECORDS OF PUBLIC UTILITIES AND LICENSEES

1. Section 125.2 is amended in paragraph (d)(3), Figure 1, Item 3.a.; in paragraph (e)(1) by redesignating subdivision (ii) as subdivision (iii), and subdivision (iii) as subdivision (iv), and by adding a new subdivision (ii); in paragraph (e)(2) by adding a new sentence at the end of subdivision (ii); and by redesignating paragraph (j) as paragraph (j)(1) and adding a new subparagraph (2), to read as follows:

§ 125.2 General instructions.

* * * * *

(d) * * *

(3) * * *

Figure 1.—*Record Media*

Record media/form	Media expected life	Comments and standards
1 * * *		
2 * * *		
3. Microforms. a. Microfilm (including computer output microfilm (COM), microfiche, jackets, and aperture cards).	Archival permanency.	Assumes storage in a controlled environment with a temperature and humidity range of 60°80°F. and 40–50%, respectively. (Ref. American National Standard Institute (ANSI) standard #PH 1.28–1976, PH 1.41–1976 and PH 5.4–1970.)

• • •

(e) • • •

(1) • • •

(ii) When the microform record series is a product of Computer Output Microfilm (COM), the certification statement may be retained separetely; only the initials of the official validating or confirming the data and the date of such validation or confirmation must appear in the title or heading of each microfiche or record series jacket. Each COM microform record series must be closed with a clear and standard microform notation indicating the completion of the series and the date.

• • • • •

(v) • • • When a retrieval system (e.g., image count indexing ("blipping")) is used, the supplemental or retaken film may be attached at the end of the series, if provisions at the beginning of the series advise the viewer of the location of the problem frames and the supplemental or retaken images.

• • • • •

(j) • • •

(1) • • •

(2) Continuing plant inventory records for each plant account must be classified to show the quantity and costs of the various record or retirement units. These records must contain the following:

(i) Name of item and manufacturer's code number, or, if built by the utility, engineering studies and details of materials used;

(ii) Location of the unit and the department responsible for it;

(iii) Date acquired or transferred to plant-in-service;

(iv) Cost;

(v) Estimates of service life and salvage value;

(vi) Details of depreciation accounting, such as monthly and yearly percentage rates and actual dollar deductions; all additions, modifications and retirements; accumulated depreciation amounts and information as to whether depreciation is calculated on a unit or group basis; and

(vii) The asset control account to which costs are charged.

• • • • •

2. Section 125.3 is amended in Item 22.1(e); in Items 22.2 (e) through (l) by revising the periods of retention; in Item 39 by applying footnote No. 5 thereto; in Item 40(b); and in Item 65 by adding a new sub-item (d), to read as follows:

§ 125.3 Schedule of records and periods of retention.

Schedule of Records and Periods of Retention

Description	Retention period
• • • • •	
22.1 Production—electric (less nuclear):	
• • • • •	
(e) Station and system generation reports and clearance logs with supporting data	25 years. See § 125.2(j)
• • • • •	
22.2 Production—nuclear:	
• • • • •	
(e) Records and prints of changes made to the plant as described in the final safety analysis report	10 years after plant is retired.
• • • • •	
39. Records of accumulated provisions for depreciation and depletion of utility plant:	
(a) Detailed records or analysis sheets segregating the accumulated depreciation according to functional classification of plant.	25 years.
• • • • •	
40. Procurements:	
• • • • •	
(b) Supporting documents including accepted and unaccepted bids or proposals evidencing all relevant elements of the procurement	6 years. See § 125.2(j)
• • • • •	
65. Reports to Federal and State regulatory commissions:	
• • • • •	
(d) Cost of service reports filed under section 133 of the Public Utility Regulatory Policies Act (PURPA). (See 18 CFR Part 290.)	5 years.

• • • • •

PART 225—PRESERVATION OF RECORDS OF NATURAL GAS COMPANIES

3. Section 225.2 is amended in paragraph (d)(3) Figure 1, Item 3.a.; in paragraph (e)(1) by adding "series" after "record" in line 1 of subdivision (i), by redesignating subdivision (ii) as subdivision (iii), and subdivision (iii) as subdivision (iv), and by adding a new subdivision (ii); in paragraph (e)(2) by adding a new sentence at the end of subparagraph (ii); by redesignating paragraph (j) as paragraph (j)(1) and adding a new subparagraph (2), to read as follows:

§ 225.2 General instructions.

• • • • •

(d) • • •

(3) • • •

Figure 1.—*Record Media*

Record media form	Media expected to be	Comments and standards
1 • • •		
2 • • •		
3. Microforms.		
a. Microfilm (including Computer Output Microfilm (COM), Microfiche, jackets, and aperture cards)	do	Assumes storage in a controlled environment with a temperature and humidity range of 60°–80° F. and 40–50%, respectively. (Ref. American National Standard Institute (ANSI) standard #PH 1.28–1976, PH 1.41–1976 and PH 5.4–1970.)

• • • • •

(e) • • •

(1) • • •

(i) Each microform record series shall contain • • •

(ii) When the microform record series is a product of Computer Output Microfilm (COM), the certification statement may be retained separately; only the initials of the official validating or confirming the data and the date of such validation or confirmation must appear in the title or heading of each microfiche or record series jacket. Each COM microform record series must be closed with a clear and standard microform notation indicating the completion of the series and the date.

* * * * *

(3) * * *

(ii) * * * When a retrieval system *(e.g.,* image count indexing ("blipping") is used, the supplemental or retaken film may be attached at the end of the series, if provisions at the beginning of the series advise the viewer of the location of the problem frames and the supplemental or retaken images.

* * * * *

(j) * * *

(1) * * *

(2) Continuing plant inventory records for each account must be classified to show the quantity and costs of the various record or retirement units. These records must contain the following:

(i) Name of item and manufacturer's code number, or, if built by the company, engineering studies and details of materials used;

(ii) Location of the unit and the department responsible for it;

(iii) Date acquired or transferred to plant-in-service;

(iv) Cost;

(v) Estimates of service life and salvage value;

(vi) Details of depreciation accounting such as monthly and yearly percentage rates and actual dollar deductions; all additions, modifications and retirements; accumulated depreciation amounts and information as to whether depreciation is calculated on a unit or group basis; and

(vii) The asset control account to which costs are charged.

* * * * *

4. Section 225.3 is amended in Item 39 by applying footnote no. 5 thereto; in Item 40(b); and in Item 65 by adding a new sub-item (d), to read as follows:

§ 225.3 Schedule of records and periods of retention. * * * * *

Schedule of Records and Periods of Retention

Description	Retention period
* * * * *	
39. Records of accumulated provisions for depreciation and depletion of utility plant:	
(a) Detailed records or analysis sheets segregating the accumulated depreciation according to functional classification of plant	25 years [5]
* * * * *	
40. Procurements:	
* * * * *	
(b) Supporting documents including accepted and nonaccepted bids or proposals evidencing all relevant elements of the procurement	6 years. See § 225.2(j).
* * * * *	
65. Report to Federal and State regulatory commission:	
* * * * *	
(d) Reports concerning first sales under sections 105, 106(b), and 109 of the Natural Gas Policy Act (NGPA). (See CFR Part 276.):	
(1) Books and records	3 years after filing date
(2) Contracts	3 years after expiration
* * * * *	

¶ 32,096 Ceiling Prices; High-Cost Gas Produced From Tight Formations (Wyoming-3)

45 F. R. 76700 (November 20, 1980).

18 CFR Part 271

[Docket No. RM79-76; Wyoming-3]

Ceiling Prices; High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Wyoming Oil and Gas Conservation Commission that the Fort Union Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 15, 1980.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 1, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or Victor Zabel, (202) 357-8559.

I. Background

On November 7, 1980, the State of Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Fort Union Formation located in the Pinedale Field, Sublette County, Wyoming be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Wyoming's recommendation that the Fort Union Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Wyoming's recommendation. Wyoming's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation lies entirely within Sublette County, Wyoming, under the Pinedale Anticline. The recommended area is approximately 45 miles long and 12 to 14 miles wide, trending in a northwesterly-southeasterly direction. The vertical limits of the Fort Union Formation are defined by the Wasatch Formation above and the Lance Formation below at an average measured depth interval of 7258 feet to 10,516 feet. The Fort Union Formation averages 3250 feet in thickness.

III. Discussion of Recommendation

Wyoming claims in its submission that evidence gathered through information and testimony presented at a public hearing in Docket No. 120-80-(A), Cause No. 2, convened by Wyoming on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without

stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Wyoming further asserts that Rule 320 of the Wyoming Oil and Gas Conservation Commission's Rules and Regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Wyoming that the Fort Union Formation, as described and delineated in Wyoming's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before December 15, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Wyoming—3), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 1, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Wyoming's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding a new subparagraph (19) to read as follow:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(2) through (18) [Reserved].

(19) *Fort Union Formation in Wyoming.* (i) *Delineation of formation.* The Fort Union Formation is found in the Pinedale Field in Sublette County, Wyoming. RM79-76 (Wyoming—3)

(ii) *Depth.* The Fort Union Formation is defined as that formation occurring between the Wasatch Formation above and the Lance Formation below at an average measured depth interval of 7,258 feet to 10,516 feet.

¶ 32,097 High-Cost Gas Produced From Tight Formations; Ceiling Prices (Colorado-7)

45 F. R. 78701 (November 20, 1980).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-7)]

High-Cost Gas Produced From Tight Formations; Ceiling Prices

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado Oil and Gas Conservation Commission that the Dakota Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 19, 1980.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 4, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357.8299 or Victor Zabel, (202) 357-8559.

Issued November 19, 1980.

I. Background

On November 10, 1980, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Dakota Formation located in La Plata County, Colorado be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Dakota Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation lies entirely within La Plata County, Colorado and underlies an area located on the north flank of the San Juan Basin and east of the city of Durango, Colorado. It is bounded on the south by the Southern Ute Indian Reservation boundary line and bounded on the north by the outcrop pattern of the Dakota and Mesaverde Formations. The recommended area contains approximately 118,238 acres, of which 27 percent is Federal, 5 percent State and 68 percent fee. The vertical limit to the top of the Dakota Formation ranges from 7500 to 8000 feet and averages 7600 feet. The vertical limit of the base of the Dakota Formation is defined by the top of the Morrison Formation. The Dakota Formation ranges from approximately 210 to 230 feet in thickness.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information

and testimony presented at a public hearing in Cause No. NG–10, convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilizied production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that Rule 317 of the Colorado Oil and Gas Conservation Commission's Rules and Regulations assures that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Dakota Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before December 19, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–7), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 4, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding a new subparagraph (20) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(2) through (19) [Reserved]

(20) *Dakota Formation in Colorado*

(i) *Delineation of formation.* The Dakota Formation is found in La Plata County, Colorado. RM79–76 (Colorado–7)

(ii) *Depth.* The Dakota Formation is defined as that formation, the depth to the top of which ranges from 7500 to 8000 feet, and the bottom of which is defined by the top of the Morrison Formation.

¶ 32,098 High-Cost Gas Produced From Tight Formations; Ceiling Prices (Colorado-8)

45 F. R. 78702 (November 26, 1980).

18 CFR Part 271

[Docket No. RM 79-76 (Colorado-8)]

High-Cost Gas Produced From Tight Formations; Ceiling Prices

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Colorado Oil and Gas Conservation Commission that the Sanastee Formation and the Dakota Formation each be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 19, 1980.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 4, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or Victor Zabel, (202) 357-8559.

Issued: November 19, 1980.

I. Background

On November 10, 1980, the Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Sanastee and Dakota Formations located in La Plata and Archuleta Counties, Colorado each be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that these formations be designated tight formations should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formations lie within La Plata and Archuleta Counties, Colorado in an area which is located on the north flank of the San Juan Basin, southeast of the City of Durango, Colorado, and south of the Southern Ute Indian Reservation boundary line. The recommended area is approximately 62,867 acres, of which 27 percent is Federal, 18 percent Indian, 2 percent state and 55 percent fee. The Sanastee Formation is found at intervals of 7550 to 7700 feet and is approximately 105 to 120 feet thick. The Dakota Formation is found at a depth of approximately 7600 feet and is approximately 210 to 230 feet thick.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG-11 convened

by Colorado on this matter demonstrates, for each formation, that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stablilized production rate, against atmospheric pressure, of wells completed for production from the recommended formations, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formations is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that typical casing design of wells drilled in the area protects fresh water aquifers in the area, as required by the rules and regulations of the Colorado Oil and Gas Conservation Commission.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado, that the Sanastee Formation and Dakota Formation, as described and delineated in Colorado's recommendation as filed with the Commission, each be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before December 19, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Colorado-8) and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concernig the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 4, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraphs (21) and (22) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(2) through (20) [Reserved].

(21) *Sanastee Formation in Colorado*

(i) *Delineation of formation.* The Sanastee Formation is found in La Plata

and Archuleta Counties, Colorado. It is located southeast of the City of Durango, Colorado, and is bounded on the north by the southern boundary of the Southern Ute Indian Reservation. RM79-76 (Colorado-8)

(ii) *Depth.* The Sanastee Formation is defined as that formation occurring within the Mancos shale at intervals from approximately 7500 to 7700 feet.

(22) *Dakota Formation in Colorado*

(i) *Delineation of formation.* The Dakota Formation is found in La Plata and Archuleta Counties, Colorado. It is located southeast of the City of Durango, Colorado, and is bounded on the north by the southern boundary of the Southern Ute Indian reservation. RM79-76 (Colorado-8)

(ii) *Depth.* The Dakota Formation is defined as that formation the depth to the top of which averages approximately 7600 feet and the base of which is defined by the top of the Morrison Formation.

¶ 32,099 High-Cost Gas Produced From Tight Formations; Ceiling Prices (Colorado-9)

45 F. R. 78703 (November 26, 1980).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-9)]

High-Cost Gas Produced From Tight Fountains; Ceiling Prices

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Colorado Oil and Gas Conservation Commission that the Corcoran Formation and the Cozzette Formation each be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 22, 1980.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 5, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or Victor Zabel, (202) 357-8559.

Issued November 20, 1980.

I. Background

On November 10, 1980, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Corcoran and Cozzette Formations located in Mesa and Garfield Counties, Colorado be designated as tight formations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Corcoran and Cozzette Formations be designated as tight formations should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formations lie within Mesa and Garfield Counties, Colorado in an area which is located on the southwest flank of the Piceance Basin, northeast of the city of Grand Junction, Colorado. The area, known locally as the Wagon Track Tight Gas Sand area, includes part of the Shire Gulch Field and all of Horseshoe Canyon, Winter Flats and Hancock Gulch Units. The recommended area is approximately 150,176 acres, of which 93 percent is Federal, and 7 percent is fee. The average depth to the producing interval of the Cozzette Formation is 2,478 feet. The Cozzette Formation is approximately 175 feet thick. The Corcoran Formation is found at a depth of approximately 2,673 feet and is approximately 150 feet thick. The Corcoran and Cozzette Formations consist of one or more sandstone benches and have been identified as

members of the Mount Garfield Formation of the Mesaverde Group.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–12, convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that typical casing design of wells drilled in the area protects fresh water aquifers in the area, as required by the rules and regulations of the Colorado Oil and Gas Conservation Commission.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Corcoran Formation and the Cozzette Formation as described and delineated in Colorado's recommendation as filed with the Commission, be designated as tight formations pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before December 22, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–9), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 5, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraphs (23) and (24) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, as subindexed below, and is also located in the official files of the

jurisdictional agency that submitted the recommendation.

* * * * *

(5) through (22) [Reserved].

(23) *Cozzette Formation in Colorado*

(i) *Delineation of formation.* The Cozzette Formation is found in Mesa and Garfield Counties, Colorado. It is located northeast of the city of Grand Junction, Colorado, and occupies an area known locally as the Wagon Track Tight Gas Sand area. RM79-76 (Colorado—9)

(ii) *Depth.* The Cozzette Formation is defined as that formation occurring within the Mount Garfield Formation of the Mesaverde Group and which is found at an average measured depth of 2,478 feet.

(24) *Corcoran Formation in Colorado*

(i) *Delineation of formation.* The Corcoran Formation is found in Mesa and Garfield Counties, Colorado. It is located northeast of the city of Grand Junction, Colorado, and occupies an area locally known as the Wagon Track Tight Gas Sand area. RM79-76 (Colorado—9).

(ii) *Depth.* The Corcoran Formation is defined as that formation occurring within the Mount Garfield Formation of the Mesaverde Group and which is found at an average depth of 2,673 feet.

¶ 32,100 High-Cost Gas Produced From Tight Formations (Texas-6)

45 F. R. 80163 (December 9, 1980).

18 CFR Part 271

[Docket No. RM79-76; Texas-6]

High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

December 3, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Texas Railroad Commission that the Midway Sandstone Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on January 5, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 18, 1980.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or William Bushey, (202) 357-8590.

SUPPLEMENTARY INFORMATION:

I. Background

On November 19, 1980, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980) that the Midway Sandstone Formation located in the southeastern part of the State of Texas be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Midway Sandstone Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Midway Sandstome Formation incountered in the northwestern portion of Montgomery County, Texas, and the southeastern portion of Grimes County, Texas, be designated as a tight formation. The particular area being recommended intails a 2.5 mile radius around a well which is located 5,050' east of the western boundary and 494' north of the southern boundary of the Ann White Survey A-43. The recommended area is composed of portions of the Ann White Survey A-43 the William Landrum Survey A-21, the William Rankin Survey A-30, the Jacob Shannon Survey A-35, the Asa Yeamans Survey A-792 and the J. Gillett Survey A-791, all in Montgomery County; and in Grimes County, the Asa Yeamans Survey A-63 and the J. Gillett Survey A-18. The Midway Formation is located below the Lower Wilcox Formation and above the Navarro Formation. The top of the recommended portion of the Midway Formation is located at an approximate

depth of 11,746 feet and the base is located at an approximate depth of 11,774 feet, giving a thickness of 28 feet.

III Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy.

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Midway Sandstone Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before January 5, 1980. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—6), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 18, 1980. (Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3432.)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (25) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(5) through (24) [Reserved]

(25) *Midway Sandstone Formation in Texas.*—(i) *Delineation of formation.* The Midway Sandstone Formation is found in the northwestern portion of Montgomery County and the southeastern portion of Grimes County, Texas.

(ii) *Depth.* The top of the Midway Formation is located at an approximate depth of 11,746 feet and the base is located at an approximate depth of 11,774 feet giving a thickness of 28 feet.

¶ 32,101 High-Cost Gas Produced From Tight Formations (Texas-7)

45 F. R. 85779 (December 30, 1980).

18 CFR Part 271

[Docket No. RM79-76 (Texas-7)]

Ceiling Prices

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Texas Railroad Commission that the Lower Wilcox Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on January 21, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on January 7, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8299 or John Bassett/Ting Chin, (202) 357-8595.

SUPPLEMENTARY INFORMATION:

Issued: December 19, 1980.

Federal Energy Regulatory Commission

I. Background

On December 11, 1980, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Lower Wilcox Formation, located in the southeastern part of the State of Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Lower Wilcox Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Lower Wilcox Formation, encountered in the southern portion of Austin County, the northern portion of Wharton County, and the eastern portion of Colorado County, Texas, be designated as a tight formation. The particular area being recommended entails a 2.5 mile radius around a well which is located 467 feet from the southwestern boundary and 650 feet from the northwestern boundary of the Frank R. Moore Survey A-377 in Austin County. (A more detailed description of the recommended area is contained in the recommendation on file with the Commission.) The Lower Wilcox Formation is located below the Claiborne Formation and above the Midway Formation. The top of the recommended portion of the Lower Wilcox Formation is located at an approximate depth of 11,700 feet and the base is located at an approximate depth of 12,700 feet, giving a thickness of 1,000 feet.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information

and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy.

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Lower Wilcox Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before January 21, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—7), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than January 7, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (27) to read as follows:

§ 271.703 Tight Formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(11) through (26) [Reserved]

(27) *Lower Wilcox Formation in Texas*

(i) *Delineation of formation.* The Lower Wilcox Formation is found in the southern portion of Austin County, the northern portion of Wharton County, and the eastern portion of Colorado County, Texas.

(ii) *Depth.* The top of the Lower Wilcox is located at an approximate depth of 11,700 feet and the base is located at an approximate depth of 12,700 feet, giving a thickness of 1,000 feet.

Proposed Regulations

46 Federal Register (1981)

¶ 32,102 High-Cost Gas Produced From Tight Formations (Ohio-1)

46 F. R. 941 (January 5, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Ohio-1)]

High Cost Gas Produced From Tight Formations; Ceiling Prices

Issued: December 23, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Ohio Department of Natural Resources, Oil and Gas Division, that the Clinton Sandstone Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on January 23, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on January 9, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299 or John Roy Johnson, (202) 357–8731.

SUPPLEMENTARY INFORMATION:

I. Background

On December 9, 1980, the Ohio Department of Natural Resources, Division of Oil and Gas (Ohio), submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980) that the Clinton Sandstone Formation located in eastern Ohio be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Ohio's recommendation that the Clinton Sandstone Formation be designated as a tight formation should be adopted. Ohio's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Ohio recommends that the Clinton Sandstone Formation encountered in eastern Ohio be designated as a tight formation. The recommendation includes only those portions of the Clinton Sandstone Formation which Ohio designated as meeting tight formation guidelines. The Clinton Sandstone is a driller's name referring to a sequence of interbedded sandstones, siltstones, and shales of the Silurian System that lie on the northwestern flank of the Appalachian Basin in

eastern Ohio. Regionally, the Clinton Sandstone Formation dips to the southeast approximately 50 feet per mile. Net sandstone thickness is a maximum of 80 to 90 feet in eastern Ohio. The Clinton Sandstone Formation thins westward and eventually pinches out in the subsurface of central Ohio in an erratic zone extending from Lorain County in northern Ohio to Lawrence County in southern Ohio.

III. Discussion of Recommendation

Ohio claims in its submission that evidence gathered through information and testimony presented at public hearings held July 15, 1980, and November 10, 1980, by Ohio on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Ohio further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Ohio that portions of the Clinton Sandstone Formation, as described and delineated in Ohio's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views, or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before January 23, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Ohio—1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than January 9, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Ohio's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (26) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) * * *

(11) through (25) [Reserved]

. (26) *Clinton Sandstone Formation in Ohio.*

(i) *Delineation of formation.* The portions of the Clinton Sandstone Formation that the Ohio Department of Natural Resources, Division of Oil and Gas, has designated as a tight formation are found in the eastern half of Ohio.

(ii) *Depth.* The Clinton Sandstone is defined as that formation occurring within the Silurian System between the Dayton Limestone and the Queenston Shale found at approximately 2,500 feet in the updip areas near its pinch out, dipping to the southeast approximately 50 feet per mile.

¶ 32,103 Exemption From the Licensing Requirements of a Category of Small Hydroelectric Power Projects With an Installed Capacity of Five Megawatts or Less

46 F. R. 1291 (January 6, 1981).

18 CFR Parts 4 and 375

[Docket No. RM81-7]

Exemption From the Licensing Requirements of a Category of Small Hydroelectric Power Projects With an Installed Capacity of Five Megawatts or Less

Issued December 22, 1980

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking; Notice of Findings of No Significant Impact; Notice of Intent to Prepare an Environmental Impact Statement.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to exempt from the licensing requirements of Part I of the Federal Power Act two categories of small hydroelectric power projects. One such category of these projects is characterized by a proposed installed capacity of 100 kilowatts or less and a second category of such projects is characterized by a proposed installed capacity of 5 megawatts or less and certain specified physical characteristics and environmental effects. The proposed rule constitutes a means of providing for exemption of a category of projects under section 408 of the Energy Security Act of 1980.

The proposed rule is designed to encourage the development of small hydropower facilities by providing a method of relieving them from certain regulatory requirements.

DATES: Written comments by February 13, 1981. Oral comment presentations and scoping meetings:

January 21, 1981, 10:00 a.m., Washington, D.C.
January 23, 1981, 10:00 a.m., Boston, MA.
January 27, 1981, 10:00 a.m., Denver, CO.
January 29, 1981, 10:00 a.m., San Francisco, CA.

ADDRESSES: Send comments to—Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

The hearings will be held at the following locations:

January 21, 1981, Federal Energy Regulatory Commission, 825 N. Capitol Street, Hearing Room A, Washington, D.C. 20426.
January 23, 1981, John W. McCormack Post Office and Court House, Room 208, Congress Street, Boston, MA 02109.
January 27, 1981, Holiday Inn, Cripple Creek Room, 1450 Glen Arm Place, Denver, CO 80202.
January 29, 1981, Holiday Inn/Civic Center, Gold Room A, B, and C, 50 Eight Street, San Francisco, CA 94103.

FOR FURTHER INFORMATION CONTACT:

Ronald A. Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, 825 N. Capitol Street, N.E., Washington, D.C. 20426, (202) 376-9171.
James J. Hoecker, Division of Regulatory Development, Office of the General Counsel, 825 N. Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9342.

The Federal Energy Regulatory Commission (Commission) proposes to exempt from the licensing requirements of Part I of the Federal Power Act (Act) two categories of small hydroelectric power projects that have been determined not to have a significant impact on the quality of the human environment. The proposed rule would

implement in part section 408 of the Energy Security Act of 1980 (ESA).[1] Under the rule as proposed, the Commission would exempt from the licensing requirement of the Act any small hydroelectric power project that belongs in either of two categories with specified characteristics. Exemption of one category of projects would be effective on the date that the Commission receives a brief notice of exemption from licensing. Exemption of a second category would date from the effective date of the rule. This proposed rulemaking is the first exercise of the Commission's discretion under section 408(b) of the ESA to exempt "classes or categories" of projects.

I. Background

Title IV of the ESA, also known as "The Renewable Energy Resource Act of 1980," amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to authorize the Commission to exempt certain small hydroelectric power projects on a case-by-case basis or by class or category of such projects, from all or part of the requirements of Part I of the Act, including any licensing requirement.

Section 408 grants the Commission discretion to provide exemption under certain specified conditions. The proposed installed capacity of a project may not exceed 5 megawatts. To be exemptible, a project must utilize the water power potential of an existing dam, unless it is a project that will utilize a so-called "natural water feature" that does not require the creation of a dam or man-made impoundment. Such a natural water feature will commonly be an elevated lake or a waterway the topographical features of which permit diversion of some waters for purposes of power generation.

Section 408 also provides that certain environmental requirements apply to those projects that the Commission exempts from licensing. Those requirements include the National Environmental Policy Act of 1969, the Endangered Species Act, and the Fish and Wildlife Coordination Act and the related consultation provisions in section 30 of the Federal Power Act that apply to exemption of small conduit hydroelectric facilities.

On November 7, 1980, the Commission issued Order No. 106,[2] which establishes procedures for exempting from all or part of Part I of the Act any small hydroelectric power project having a proposed installed capacity of 5 megawatts or less by means of case-by-case analysis and determination of the advisability of exempting any project and the environmental impact of that action. The procedures set forth in Order No. 106 rely initially on the submission of an application for exemption by any person, if only Federal lands are involved, or by a person that holds all the necessary real property interests in non-Federal lands, if any non-Federal lands are involved. If the Commission does not explicitly act on an application for exemption from licensing within a specified time, absent a suspension of the time for action, the application is deemed granted.

The rule proposed in this docket exempts from licensing two categories of small hydroelectric power projects. The exemption of the first category of such projects, described in § 4.109(a) applies to any project with a proposed installed generating capacity of more than 100 kilowatts but not more than 5 megawatts and specific other characteristics and is made effective by submittal to the Commission of a notice of exemption from licensing by the same classes of persons who may file

[1] Pub. L. 96-294, 94 Stat. 611. Section 408 of the ESA amends, *inter alia*, sections 405 and 408 of the Public Utilities Regulatory Policies Act of 1978 (PURPA) (16 U.S.C. §§ 2705 and 2708).

[2] 45 *Fed. Reg.* 76115, November 18, 1980. The final rule in Order No. 106 established Subpart K of Part 4 of the Commission's Regulations, which subpart would be revised and expanded by the proposed rule in this docket.

application for exemption from licensing under the newly promulgated case-by-case regulations. Projects within the second category, described in § 4.113(a), are made exempt by operation of the rule and may not exceed 100 kilowatts in installed capacity.

This generic exemption differs from Order No. 106 in several respects. Any small hydroelectric power project with a proposed installed capacity of 5 megawatts or less is exemptible under case-by-case method; only projects with specified characteristics, which the Commission finds will not significantly affect the quality of the human environment, are generically exempted.[3] The case-specific procedures address both exemption from licensing and exemption from provisions of Part I of the Act other than licensing; the generic exemption applies only to exemption from licensing. While the case-specific procedures will apply to projects that utilize for power generation either an existing dam or natural water feature, the proposed generic exemption of both categories of projects will apply only to projects at an existing dam. Finally, under the case-specific approach, the Commission is required to consider and act on each project separately; generic exemption is accomplished under the terms of the rule alone. It is estimated that at least 20% and perhaps as much as 75% of the developable small hydroelectric power projects 5 megawatts and less fall within the categories of projects covered by this exemption rule.

II. Summary of the Proposed Rules.

The proposed rule revises parts of the existing Subpart K of Part 4 to divide the exemption regulations into the existing case-specific exemption provisions (§§ 4.103 through 4.108) and the proposed generic exemption provisions (§§ 4.109 through 4.113). The applicability section (§ 4.101) and the definitions (§ 4.102) pertain to exemption of all small hydroelectric power projects under Subpart K. The general waiver provision in § 4.103(d) is applicable only to case-specific exemptions from licensing.

Section 4.109 sets forth a set of criteria under which a project may qualify for exemption from licensing as part of a class of exempt projects. Small hydroelectric power projects that utilize a natural water feature for electric power generation are not eligible for exemption as part of either category of projects more than 100 kilowatts described in § 4.109(a) or the projects of 100 kilowatts or less because little is now know about the probable physical charactertistics or environmental impact of those kinds of projects.

Section 4.109 also provides that projects of more than 100 kilowatts are exempted effective on the date that the Commission accepts for filing (see § 4.31(e)) a notice of exemption identifying both the project and the person developing it. The filing person must certify that the project meets the qualifications in § 4.109(a) and will not affect particular aspects of the environment. The certification requirements in § 4.112 (b) and (c) operate in conjunction with the criteria for exemption in § 4.109(a).

Exemption of any project of 100 kilowatts or less would be effective as of the effective date of the regulation, according to § 4.113(b). Neither the terms and conditions in § 4.111 nor the notice of exemption requirement in § 4.112 would apply to the projects exempted under § 4.113. With respect to the capacity that must be installed or increased at any exemptible site, under the terms of the statute, the effective date of the regulation will be considered the date of a notice of exemption or application for exemption for purposes of applying the definition of a small hydroelectric power project.

[3] The Commission will consider another rulemaking to exempt from licensing a category of small hydroelectric power projects that may have significant environmental impacts. This class of projects will be the subject of an Environmental Impact Statement. Any projects that do not qualify for generic exemption may be exemptible under the case-by-case approach.

Section 4.110 provides limitations on the submittal of notices of exemption for exempted projects in order to establish fixed relationships among various persons who may seek to develop a site. These provisions are similar to the provisions in § 4.110, but adapted to the generic exemption context, and are proposed for the same kind of reasons explained in Docket No. RM80-65 for case-by-case exemptions. Section 4.110(a) states that a notice of exemption may not be filed under the rule if a permit or license is outstanding or a permit or license application has been filed, unless it is the permittee or licensee who files the notice of exemption. A permit or license applicant may file a notice of exemption if the project is eligible under § 4.109(a), the applicant is qualified under § 4.109(c) to file such notice, and no competing application for that project was filed during the entire period provided for protest and intervention in the notice of application. Upon filing of a notice of exemption, any outstanding permit is cancelled and any license is deemed terminated.

If a project is exempt under the rule, the Commission will not accept an application for license or preliminary permit according to both §§ 4.110(b) and 4.113(d). There are exceptions to this rule, however. If the developer of an exempted project of more than 100 kilowatts fails to get Federal approval or to begin construction on a timely basis, the Commission may revoke the exemption and accept a license application under the terms and conditions of § 4.111. License applications will also be accepted for any project 5 megawatts or less, if an applicant proposes to develop the project to an installed capacity of at least 7.5 megawatts, or if the applicant is the holder of any real property interests in non-Federal lands necessary to develop and operate the project and is a qualified applicant.

Section 4.11 sets forth standard terms and conditions of generic exemption for projects of 100 kilowatts or less that are exemptible under § 4.109(a). Conditions of the generic exemption are similar to those for case-specific exemption, except that under the proposed generic rule the owner of the exempted project must comply with any measures that fish and wildlife agencies require in the future as part of a migratory fish restoration program (Article 2). In addition, if a dam is more than 33 feet in height above streambed, impounds more than 2.5 million cubic meters of water, or is determined to have a high hazard potential, the project must have periodic safety inspections by an independent consultant and is subject to safety inspections and remedial measures that may be required by the Commission's Regional Engineer or other authorized representative, under the Commission's project safety regulations.[4]

Section 4.112 provides that any person with all of the real property interests in any non-Federal lands necessary to develop or operate the project must file a notice of exemption in order to make effective the exemption from licensing for a project of more than 100 kilowatts. (If only Federal lands are involved, any person may file a notice of exemption.)

Copies of the notice of exemption must be served on the U.S. Fish and Wildlife Service, other relevant fish and wildlife agencies, the relevant state water resource agencies or EPA, and the relevant state Historical Preservation Officer. Section 4.112(b) would require the person submitting a notice of exemption under § 4.112 to obtain agency certification about compliance with water quality standards and the absence of existing fish passage at the dam but would permit, as an option, the filing party to certify that no historical site, endangered species, or critical habitat was threatened, based on field surveys and literature surveys by

[4] This condition is written to relate to the Commission's new Regulations Governing the Safety of Water Power Projects and Project Works (Docket No. RM80-31). A final dam safety rule will be issued at about the same time as the proposed rule in this docket.

approved experts. Section 4.112 also requires a specific format for the notice of exemption, including specific certifications by the filing party on compliance with the qualifying conditions. That section also contains additional requirements for basic information important to the Commission's responsibilities for national water resource analysis, licensing of other non-exempt projects, and implementation of §§ 4.104 and 4.110 of Subpart K, as it is proposed to be amended.

Section 4.113 provides for exemption from licensing of any small hydroelectric power project with an installed capacity of 100 kilowatts or less, so-called "micro-hydro" projects, by operation of the regulation.

III. Notice of Finding of No Significant Impact and Notice of Intent To Prepare an Environmental Impact Statement

The Commission has prepared an Environmental Assessment (EA) of the exemption from the licensing requirements of the Act for the proposed category of small hydroelectric power projects pursuant to section 408 of the ESA. The Commission gives notice that, on the basis of the EA, it has determined that exempting from licensing that category of projects of more than 100 kilowatts and described in § 4.109(a) is not a major Federal action significantly affecting the quality of the human environment. The EA is incorporated by reference in the Finding of No Significant Impact. Projects in the category of small hydroelectric power projects described in § 4.109(a) of the proposed rule will have a proposed installed capacity of more than 100 kilowatts but not more than 5 megawatts, utilize for power generation the water power potential of an existing dam, and:

1. Not involve any change in the prevailing regime of storage and release of water from the impoundment;

2. Not divert water from the waterway for a distance of more than 300 feet from the toe of the dam to the point of discharge back into the waterway;

3. Not involve construction of any transmission line that has a design capacity of more than 69 kilovolts or is more than one mile long and located in a new right of way;

4. Not increase the normal maximum surface elevation of the impoundment as a result of repair or reconstruction of the existing dam;

5. Not cause a violation of applicable water quality standards;

6. Not involve construction on or alteration of any historic site;

7. Not involve construction in the vicinity of any endangered or threatened species or critical habitat as listed or designated in the regulation of the Department of the Interior; and

8. Have no significant existing upstream or downstream passage of fish at the site.

The Commission also believes that, based on its own experience,[5] a categorical exemption for all so-called "micro-hydroelectric" projects with a total proposed installed capacity of 100 kilowatts or less would not be a major Federal action significantly affecting the quality of the human environment. Because the EA does not directly address the impacts likely to occur from a category of small hydroelectric power projects delineated primarily by very small generating capacity, the Commission requests comment on the environmental consequences of an exemption from licensing for any project proposed to be developed to a capacity not to exceed 100 kilowatts, provided such project is not only part of a licensed water power project and utilizes an existing dam. This category of projects is exempted under proposed § 4.113. Exemption of such projects would differ from the exemption from licensing provided for the category described in § 4.109(a) in several respects:

[5] For example FERC Project Nos. 2907, 2987, 3017

(1) Because information regarding projects of such size is generally not important to other licensing proceedings or regional water resource management, a notice of exemption (§ 4.112) containing rudimentary data on the project need not be filed with the Commission. the exemption would date from the effective date of the rule.

(2) Environmental impacts, such as blockage of fish migration, dewatering, or effects on historic sites or water quality, are determined to be minimal. Generally, micro-hyrdo-electric projects are located on small streams and create small impoundments. Aquatic resources and the flow regime of the stream are not affected by the presence of a project with such small capacity. Small streams that have sufficient gradient to facilitate hydropower development are less likely to have water quality problems. Because of the size of the stream and impoundment, related recreational development is normally very limited.

(3) The terms and conditions of exemption in § 4.111 would not apply to such projects.

In addition, the Commission solicits comment on what the practical and environmental consequences would be if it were to exempt from licensing projects of 100 kilowatts or less which utilize for electric power generation of a natural water feature without the need for a man-made dam and impoundment.

The Commission also gives notice that it intends to prepare an Environmental Impact Statement (EIS) evaluating the effects of exempting from licensing all or part of the remainder of projects that are potentially exemptible under section 408 of the ESA, but which do not conform to all the criteria listed in § 4.109(a) and § 4.113(a). Scoping meetings for the EIS will be combined with public meetings regarding the content of this rulemaking. Those meetings are discussed below.

The EA is available for inspection at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, and at its Regional Offices in Atlanta, Georgia, New York, New York, Chicago, Illinois, San Francisco, California, and Fort Worth, Texas.

IV. Comment Procedure

Persons interested in the proposed rule are invited to submit written views, comments, or suggestions in writing concerning all or part of the regulations proposed in this notice. Pursuant to the consultation requirements of section 408 of the ESA and section 30 of the Act, Fish and Wildlife agencies will also receive letters transmitting copies of this Notice of Proposed Rulemaking and the related Environmental Assessment. The Commission requests their comments on the proposed rule. All commenters should note the requests for comment in the notice of finding of no significant impact. The Commission will consider all comments before issuing a final rule.

An original and 14 copies of all comments must be filed with the Secretary not later than February 13, 1981, at the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Comments should indicate the name, title, mailing address, and telephone number of the person to whom communications concerning the proposal may be addressed. Comments should reference Docket No. RM81-7 on the outside of the envelope and on all documents submitted to the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426 during regular business hours.

In addition to the written comment procedures, the Commission will hold public meetings for the purposes of receiving oral comments on the proposed rule and on the scope of the EIS to be prepared for a further category of projects that might be exempted from licensing. These meetings will also provide further opportunity for consultation with fish and wildlife agencies under the provisions of section 408 of the ESA and section 30 of the Act. The public will be afforded an opportunity to discuss the findings in the EA and to address environmental issues

relating to expansion of the category of exempt facilities, the impacts of the proposed rule, and the range of topics that the EIS should cover. This time, place, and location of these public meetings are as follows:

January 21, Washington, D.C., Federal Energy Regulatory Commission, 825 N. Capitol Street, Washington, D.C. 20426, 10 a.m.

January 23, Boston, MA, John W. McCormack Post Office and Court House, Congress Street, Boston, MA 02109, 10 a.m.

January 27, Denver, CO, Holiday Inn, Cripple Creek Room, 1450 Glen Arm Place, Denver, CO 80202, 10 a.m.

January 29, San Francisco, CA, Holiday Inn/Civic Center, Gold Room A, B, and C, San Francisco, CA 94103, 10 a.m.

Agencies or members of the public wishing to participate with respect to the proposed rule or the scope of the EIS should notify the Secretary of the Commission at least 10 days prior to the date of the particular public meeting. Participants are asked to supply copies of any prepared presentations at the time of the meeting.

(Energy Security Act of 1980, Pub. L. 96-294, 94 Stat. 611; Federal Power Act, as amended, 16 U.S.C. 792-828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601-2645; and the Department of Energy Organization Act, 42 U.S.C. §§ 7101-7352; E. O. 12009, 3 C.F.R. 142 (1978))

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

1. Part 4 is amended in the Table of Contents by revising the titles of §§ 4.101, 4.103, 4.104, and 4.106 and by adding to Subpart K the following section titles (§§ 4.109–4.113) to read as follows:

PART 4—LICENSES, PERMITS, EXEMPTIONS, AND DETERMINATION OF PROJECT COSTS

Subpart K—Exemptions of Small Hydroelectric Power Projects of 5 Megawatts or Less.

Sec.

4.101 Applicability.

* * * * *

4.103 General provisions for case-specific exemption.

4.104 Case specific exemption from licensing: relationships among applications, exemptions, permits, and licenses.

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4.106 Standard terms and conditions of case-specific exemption from licensing.

* * * * *

4.109 General provisions for categorical exemption from licensing for certain projects with installed capacity of more than 100 kilowatts.

4.110 Categorical exemption from licensing for projects of more than 100 kilowatts: relationships among applications, exemptions, permits, licenses, and notices of exemption.

4.111 Standard terms and conditions of categorical exemption from licensing for projects of more then 100 kilowatts.

4.112 Notice of exemption from licensing for projects of more than 100 kilowatts.

4.113 General provisions for categorical exemption from licensing for certain projects with installed capacity of 100 kilowatts or less.

2. Subpart K of Part 4 is amended by revising § 4.101 and by revising the title and paragraphs (a) and (d) of § 4.103, to read as follows:

Subpart K—Exemption of Small Hydroelectric Power Projects of 5 Megawatts or Less.

§ 4.101 Applicability.

(a) *General.* This subpart provides procedures for exemption on a case-specific or categorical basis from all or part of Part I of the Federal Power Act (Act), including licensing, for small

hydroelectric power projects as defined in § 4.102.

(b) *Case-specific exemption.* The provisions of §§ 4.103 through 4.108 apply to:

(1) exemption of any small hydroelectric power project from provisions of Part I of the Act other than licensing; and

(2) exemption of any small hydroelectric power project from licensing, except any project that has been exempted as part of a category of exemptible projects under §§ 4.109 through 4.112.

(c) *Categorical exemption of certain projects of more than 100 kilowatts.* The provisions of §§ 4.109 through 4.112 apply to exemption from licensing for any small hydroelectric power project which meets the criteria set forth in § 4.109(a) of this subpart. Such projects may be exempted by filing a notice of exemption from licensing.

(d) *Categorical exemption of certain projects of 100 kilowatts or less.* The provisions of § 4.113 apply to certain small hydroelectric power projects which have a proposed installed capacity of 100 kilowatts or less and which are categorically exempt from licensing by operation of this subpart.

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§ 4.103 General provisions for case-specific exemption.

(a) *Exemptible projects.* Subject to the provisions of paragraphs (b) and (c) of this section and §§ 4.104 through 4.106, the Commission may exempt on a case-specific basis any small hydroelectric power project from all or part of Part I of the Act, including licensing. Applications for exemption for specific projects shall conform to the requirements of §§ 4.107 or 4.108, as applicable.

• • • • •

(d) *Waiver.* In applying for case-specific exemption from licensing, a qualified exemption applicant may petition under § 1.7 of this chapter for waiver of any specific provision of §§ 4.102 through 4.107. The Commission will grant a waiver only if consistent with section 408 of the Energy Security Act of 1980.

3. Subpart K of Part 4 is amended by adding §§ 4.109 through 4.113, to read as follow:

§ 4.109 General provisions for categorical exemption from licensing for certain projects with installed capacity of more than 100 kilowatts.

(a) *Exempted projects.* Subject to the provisions of §§ 4.110 and 4.111 and effective according to paragraph (b) of this section, the Commission exempts from the licensing requirements of Part I of the act any small hydroelectric power project which has a proposed installed capacity of more than 100 kilowatts and which:

(1) Utilizes for electric power generation only the water power potential of an existing dam;

(2) Does not entail any increase in the normal maximum surface elevation of the impoundment pursuant to repair or reconstruction of a dam;

(3) Does not entail, for the purpose of generating electric power, any change from the prevailing regime of storage and release of water from the impoundment;

(4) Does not entail diversion of water from the waterway for more than 300 feet from the toe of the dam to the point of discharge into the waterway;

(5) Does not entail construction of any primary transmission line which:

(i) Has a design capacity of more than 69 kilovolts (KV); or

(ii) Is more than one mile long and located on a new right-of-way;

(6) Utilizes only a dam at which there is no significant existing upstream or downstream passage of fish;

(7) Will not cause violation of applicable water quality standards established by the U.S. Environmental Protection Agency or any state in which the project is located;

(8) Does not entail any construction on or alteration of any site included in or eligible for inclusion in the National Register of Historic Places;

(9) Does not entail construction in the vicinity of any threatened or endangered species or critical habitat, listed or designated in the regulations of the U.S. Department of the Interior; and

(10) Is not only part of a licensed water power project.

(b) *Effective date of exemption.* Any small hydroelectric power project in the category of projects specified in paragraph (a) of this section is exempted from licensing as of the date that a notice of exemption from licensing for that project, complying with the provisions of § 4.112, is deemed accepted for filing.

(c) *Who may file a notice of exemption from licensing for Category A projects.*

(1) *Only Federal lands involved.* If only the rights to use or occupy Federal lands would be necessary to develop and operate a proposed small hydroelectric power project that meets the criteria of paragraph (a) of this section, any person may file a notice of exemption from licensing for that project under § 4.112.

(2) *Some non-Federal lands involved.* If real property interests in any non-Federal lands would be necessary to develop and operate a proposed small hydroelectric power project that meets the criteria of paragraph (a) of this section, any person who has all of the real property interests in non-Federal lands necessary to develop and operate that project, or an option to obtain those interests, may file a notice of exemption from licensing for that project under § 4.112.

§ 4.110 Categorical exemption from licensing for projects of more than 100 kilowatts: relationships among applications, exemptions, permits, licenses, and notices of exemption.

For purposes of categorical exemption from licensing under §§ 4.109 through 4.112, the Commission will treat preliminary permit and license applications, preliminary permits, license, exemptions from licensing, and applications for exemption from licensing that are related to any small hydroelectric power project described in § 4.109(a), as follows:

(a) *Limitations on submission and acceptance of notices of exemption.* (1) *Unexpired permit or license.* If there is an unexpired preliminary permit or license in effect for a project, the Commission will accept a notice of exemption from licensing for any project meeting the criteria of § 4.109(a) only if the person filing the notice is the permittee or licensee. If the notice of exemption is submitted by a permittee, the permit will be deemed cancelled. If the notice of exemption is filed by a licensee, the license will be deemed terminated.

(2) *Pending permit, license, or exemption application.*

(i) *General Rule.* Except as permitted under clause (ii), the Commission will not accept a notice of exemption from licensing for any project meeting the criteria of § 4.109(a) if a preliminary permit or license application for that project, or an application for exemption of that project from licensing, has been accepted for filing.

(ii) *Exceptions.* If an application for preliminary permit, license, or exemption from licensing has been accepted for filing for a project meeting the criteria of § 4.109(a), the Commission will accept a notice of exemption from licensing for that project, if:

(A) No competing application, whether for preliminary permit, license, or exemption from licensing, has been accepted for filing for that project;

(B) The last date for filing protests or petitions or petitions to intervene, prescribed in the public notice issued for the permit or license application under § 4.31(c)(2) of this chapter, has passed;

(C) No notice of intent to file a competing preliminary permit or license application for that project has been filed in accordance with § 4.33(b) of this chapter; and

(D) The person filing the notice of exemption is the applicant for preliminary permit, license, or exemption from licensing.

(iii) *Withdrawal of pending applications.* If a notice of exemption from licensing complying with § 4.112 is filed under clause (ii), any pending application for preliminary permit, license, or exemption from licensing will be deemed withdrawn.

(b) *Limitations on submissions and acceptance of permit or license applications.* (1) *General rule.* Except as permitted under subparagraph (2) or under § 4.111 (c) or (e), the Commission will not accept a preliminary permit or license application for any small hydroelectric power project that is exempt from licensing pursuant to § 4.109.

(2) *Exceptions.* (i) If a project is exempted from licensing pursuant to § 4.109, any qualified license applicant may submit a license application that proposes to develop at least 7.5 megawatts in any exempted project.

(ii) If a project is exempted from licensing pursuant to § 4.109 and real property interests in any non-Federal lands would be necessary to develop and operate the project, any person who is both a qualified license applicant and has any of the real property interests in such non-Federal lands may submit a license application for that project. If a license application is submitted under this clause, any other qualified license applicant may submit a competing license application in accordance with § 4.33 of this part.

§ 4.111 Standard terms and conditions of categorical exemption from licensing for projects installed capacity of more than 100 kilowatts.

Any small hydroelectric power project exempted from licensing under § 4.198(a) is subject to the following standard terms and conditions:

(a) *Article 1.* The Commission reserves the right to conduct investigations under sections 4(g), 306, 307, and 311 of the Federal Power Act with respect to any acts, complaints, facts, conditions, practices, or other matters related to the construction, operation, or maintenance of the exempt project. If any term or condition of the exemption is violated, the Commission may revoke the exemption, issue a suitable order under section 4(g) of the Federal Power Act, or take appropriate action for enforcement, forfeiture, or penalties under Part III of the Federal Power Act.

(b) *Article 2.* The construction, operation, and maintenance of the exempt project must comply with any measures that any fish and wildlife agency may in the future prescribe as part of any migratory fish restoration program.

(c) *Article 3.* The Commission may accept a license application submitted by any qualified license applicant and revoke this exemption if actual construction or development of any proposed generating facilities has not begun within 18 months, or been completed within four years, from the effective date of this exemption. If an exemption is revoked, the Commission will not accept a subsequent notice of exemption from licensing or application for exemption for the project within two years of the revocation.

(d) *Article 4.* This exemption is subject to the navigation servitude of the United States if the project is located on navigable waters of the United States.

(e) *Article 5.* This exemption does not confer any right to use or occupy any Federal lands that may be necessary for the development or operation of the project. Any right to use or occupy any Federal lands for those purposes must be obtained from the administering Federal land agencies. The Commission may accept a license application submitted by an qualified license applicant and revoke this exemption if any necessary right to use or occupy Federal lands for those purposes has not been obtained within one year from the effective date of this exemption.

(f) *Article 6.* Any exempted small hydroelectric power project that utilizes a dam that is more than 33 feet in height above streambed, as defined in 18 CFR 12.30(b)(3) of this chapter, impounds more than 2,000 acre-feet of water, or has high hazard potential, as defined in

18 CFR 12.30(b)(2), is subject to the following provisions of 18 CFR Part 12:

(1) § 12.4(b)(2)(i), (ii), (iii)(B), (iv), and (v);

(2) § 12.4(e); and

(3) Subpart D.

(g) For the purposes of applying these provisions of 18 CFR Part 12, the exempted project is deemed to be a licensed project development and the owner of the exempted project is deemed to be a licensee, under the definitions in 18 CFR 13.3.

§ 4.112 Notice of exemption from licensing for projects with installed capacity of more than 100 kilowatts.

(a) *General requirement.*

Any person meeting the requirements specified in § 4.109(c) and filing a notice of exemption from licensing for any small hodroelectric power project under § 4.109(a) must submit:

(1) The original and 14 copies of the notice of exemption described in paragraph (c) of this section; and

(2) Proof of service of a copy of the notice of exemption on:

(i) The U.S. Fish and Wildlife Service and other fish and wildlife agencies;

(ii) The state Historic Preservation Officer for each state in which the project is located; and

(iii) The state water resource agency for each state in which the project is located or, if there are no applicable state water quality standards, the U.S. Environmental Protection Agency.

(b) *Certifications or surveys.* As a basis for certifying to the nature and effects of a small hydroelectric power project under paragraph (c)(4) of this section, a person filing a notice of exemption must:

(1) Obtain certification from the state water resource agency for each state in which the project is located or, if there are no applicable state water quality standards, from the U.S. Environmental Protection Agency, that the project will not cause a violation of any applicable water quality standards.

(2) Obtain certification from the U.S. Fish and Wildlife Service or the fish and wildlife agency for each state in which the project is located that there is no significant existing upstream or downstream passage of fish at any project dam;

(3) Either obtain certification from the state Historic Preservation Officer of each state in which the project is located or obtain an independent field survey and survey of the applicable literature, conducted by an archeologist approved by each applicable state Historic Preservation Officer, with respect to whether the project will entail construction on or alteration of sites included in or eligible for inclusion in the National History Register of Historic Places;

(4) Either obtain certification from the U.S. Fish and Wildlife Service or the state fish and wildlife agency for each state in which the project is located or obtain an independent field survey and survey of the applicable literature, conducted by a biologist approved by each applicable state fish and wildlife agency, with respect to whether the project entails any construction in the vicinity of any endangered or threatened species or critical habitat listed or designated in the regulations of the U.S. Department of the Interior.

(c) *Contents.* The notice of exemption from licensing required by this section must conform to the following format:

Before The Federal Energy Regulatory Commission. Notice of Exemption of Small Hydroelectric Power Project from Licensing.

(1) [Name of filing party or parties] notifies [notify] the Federal Energy Regulatory Commission that the [name of the project], a small hydroelectric power project as defined in 18 CFR 4.102, is exempt from licensing under the terms of 18 CFR 4.109 through 4.111. [If applicable: The project is currently licensed as FERC Project No. ———].

(2) The location of the project is:

[State or territory] ———

[County] ———

[Township or nearby town] ———

[River or stream] ———

[River basin] ———

(3) The exact name, business address, and telephone number of the filing party or parties are:

———

———

(4) The project includes the following features:

(i) *Dams:* [For each existing dam, identify the dam; state the date on which construction was completed and state both the dam's height above streambed and the gross storage capacity of the related impoundment as defined in 18 CFR 12.30].

(ii) *Powerplants:* [For each powerplant: identify the powerplant; state whether it is existing or proposed; state the hydraulic head; state the installed capacity in kilowatts and average annual generation in kilowatt-hours for any existing electric generating capacity; and state the proposed total installed capacity in kilowatts and the estimated average annual generation in kilowatt-hours for the proposed total installed capacity].

(iii) *Average stream flow:* The average annual streamflow is [ ] cubic feet per second.

(5) It is certified that [name of filing party or parties] has [have] complied with § 4.112(c) of the Commission's regulations and that the small hydroelectric power project conforms to the specifications set forth in § 4.109(a) of the Commission's regulations, including the following:

(i) The [each applicable state water resource agencies or U.S. Environmental Protection Agency] has [have] certified that the construction, operation, and maintenance of the project will not cause a violation of any applicable water quality standards.

(ii) The [U.S. Fish and Wildlife Service or each applicable state fish and wildlife agency] has [have] certified that there is no significant existing upstream or downstream migration of fish at any project dam.

(iii) The proposed small hydroelectric power project does not entail any construction on or alteration of any site that is included in or is eligible for inclusion in the National Register of Historic Places.

(iv) The proposed small hydroelectric power project does not entail construction in the vicinity of any threatened or endangered species or critical habitat listed or designated in the regulations of the U.S. Department of the Interior.

(6) [Signature of filing party or parties under § 1.15 of this chapter; subscription and verification under § 1.16 of this chapter].

§ 4.113 General provisions for categorical exemption from licensing for certain projects with installed capacity of 100 kilowatts or less.

(a) *Exemption.* The Commission categorically exempts from the licensing requirements of Part I of the Act, effective according to paragraph (b) of this section any small hydroelectric power project that:

(1) Utilizes for electric power generation only the water power potential of an existing dam;

(2) Has total proposed installed capacity of not more than 100 kilowatts; and

(3) Is not only part of a licensed water project.

(b) *Effective dates.* (1) *Exemption.* Any small hydroelectric power project meeting the criteria in paragraph (a) of this section is exempted from licensing as of the effective date of this section.

(2) *Proposed capacity.* For purposes of installing or increasing capacity in any project meeting the criteria in paragraph (a), under the definition of small hydroelectric power project in § 4.102(1), the effective date of this section is deemed to be the date of notice of exemption or application under this subpart.

(c) *Limitation on submissions and acceptance of permit or license applications.* For purposes of categorical exemption under this section, the Commission will treat preliminary permit and license applications, preliminary permits, licenses, and applications for exemptions from licensing that are related to a small hydroelectric power project described in § 4.113(a), as follows:

(1) *General rule.* Except as permitted under subparagraph (2), the Commission will not accept a preliminary permit or license application for any small hydroelectric power project that is exempted from licensing pursuant to § 4.113.

(2) *Exceptions.* (i) If a project is exempted from licensing pursuant to § 4.113, any qualified license applicant may submit a license application that proposes to develop at least 7.5 megawatts in any exempted project.

(ii) If a project is exempted from licensing pursuant to § 4.113 and real property interests in any non-Federal lands would be necessary to develop and operate the project, any person who is both a qualified license applicant and has any of those real property interests in non-Federal lands may submit a license application for that project. If a license application is submitted under this clause, any other qualified license applicant may submit a competing license application in accordance with § 4.33 of this part.

§ 4.102 [Amended]

4. Section 4.102(1) is amended by inserting after the words "after the date of" the words "notice of exemption or."

§ 4.104 [Amended]

5. Section 4.104 is amended by revising the title to read *"Case-specific exemption from licensing: relationships among applications, exemptions, permits and licenses."* and by deleting from the first sentence the words "this subpart" and substituting in lieu thereof the words "case-specific exemption under §§ 4.103 through 4.107".

§ 4.105 [Amended]

6. Section 4.105 is amended in the first sentence of paragraph (b)(6) by removing the words "In granting an exemption from licensing," and substituting in lieu thereof the words "In approving any application for exemption from licensing,".

7. Section 4.106 is amended by revising the title of the section, by revising the first sentence, and by revising the second sentence of paragraph (c) to read:

§ 4.106 Standard terms and conditions of case-specific exemption from licensing.

Any case-specific exemption from licensing granted for small hydroelectric power project is subject to the following standard terms and conditions:

* * * * *

(c) *Article 3.*

* * * * *

If an exemption is revoked, the Commission will not accept a subsequent application for exemption or a notice of exemption from licensing within two years of the revocation.

* * * * *

7. Section 375.308 is amended by revising paragraphs (n) and (o) to read as follows:

§ 375.308 Delegations to the Director of the Office of Electric Power Regulation.

* * * * *

(n) Issue deficiency letters regarding electric rate schedule filings, refund reports, corporate applications for the sale of facilities with respect to interlocking directorates, exemption applications of notices of exemption filed under Subparts J or K of Part 4 of this chapter, and applications filed under Part I of the Federal Power Act.

(o) Reject a rate filing, an application filed under Part I of the Federal Power Act, an application or other filing under section 405 of the Public Utility Regulatory Policy Act of 1978, or a non-complying notice of exemption from licensing filed under §§ 4.109 through 4.112 of this chapter, unless accompanied by a request for waiver in conformity with § 1.14(a)(2) of this chapter, if it fails patently to comply with applicable statutory requirements or Commission rules, regulations and orders.

* * * * *

¶ 32,104 Elimination of Requirement for Federal Entities to File Reports Pursuant to § 141.1

46 F. R. 1743 (January 7, 1981).

18 CFR Part 141

[Docket No. RM81-3]

Proposed Rulemaking To Eliminate Requirement of Federal Entities To File Reports Pursuant to § 141.1

Issued December 30, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to eliminate the entire requirement for Federal entities to file the "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)," FPC Form No. 1 and its modified versions, which are prescribed by 18 CFR 141.1.

The information collected in Federal filings of Form No. 1 and its modified versions includes summary financial data, balance sheet supporting data, income statement supporting data and electric plant, sales, operating and statistical data.

These data have been collected in conjunction with the Commission's headwater benefits program and Federal rate cases. Some of this information, however, supplements and duplicates data submitted for assessment of headwater benefits. The information is also used to supplement Federal rate filings, but is of very limited use in its present format. The Commission, therefore, finds that the data currently filed by Federal entities pursuant to § 141.1 are not useful for the performance of its regulatory reponsibilities and can be elimited in their entirely.

Revisions to consolidate and standardize the headwater benefits and Federal rate filing requirements are expected in the next year, and may include data similar to that proposed for deletion herein. In the meantime, the Commission will continue to use current Federal rate and and headwater benefits submissions, and specific data requests to obtain information needed for review in these areas.

DATES: Comments are due by January 29, 1981.

ADDRESS: Comments on this Notice should be addressed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM81-3.

FOR FURTHER INFORMATION CONTACT:

Ellen Brown, Office of Program Managements, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 3317, Washington, D.C. 20426, (202) 357-8182.

The Federal Energy Regulatory Commission (Commission) is engaged in an ongoing effort to eliminate unnecessary reporting burdens and to more clearly define its reporting requirements. This rulemaking to entirely eliminate the filing by Federal entities of information pursuant to 18 C.F.R. § 141.1, "Form No. 1, Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)", is part of that effort, and reflects a new evaluation of the data required by the Commission for regulatory purposes.

There is also currently pending at the Commission a rulemaking proceeding to revise Form No. 1—the major annual report filed with the Commission by *non*-Federal (*i.e.*, investor-owned) Class A and Class B electric utilities, licensees and other entities. (*See* Notice of Proposed Rulemaking, issued July 10, 1980, Docket No. RM80-55, 45 FR 47704, July 16, 1980.) That proceeding is, however, separate and distinct from the instant rulemaking, which solely addresses the versions of Form No. 1 filed by *Federal* entities that generate and sell electricity.

I. Background

The Commission is authorized to require information in § 141.1 pursuant to sections 304 and 311 of the Federal Power Act (16 U.S.C. §§ 792–828(c)). Section 141.1 requires annual collection of information from Class A and Class B electric utilities, licensees and other entities, including Federal entities engaged in the generation, transmission, distribution or sale of electric energy.[1] The prescribed filing primarily includes summary financial data; balance sheet supporting data; income statement supporting data; and electric plant, sales, operating and statistical data.

The reports submitted by Federal entities pursuant to § 141.1 are all modified versions of Form No. 1. The modified Form No. 1 reports are filed by a variety of Federal entities, including Power Marketing Administrations within the Department of Energy, and the Water and Power Resources Service and Bureau of Indian Affairs within the Department of Interior. Among these Federal versions of Form No. 1 is "Form No. 1002", an unofficial version of the Form No. 1 which is filed by several projects within the Army Corps of Engineers. All of these Federal reports are currently required to be filed on or before December 31 of each year, and are based on data from the immediately preceding fiscal year (October 1 through September 30).[2]

II. Use of the Data

The information collected from filings by Federal agencies of Form No. 1[3] has been used in the Commission's headwater benefits program (*see* 18 CFR 11.25—11.31, 13.1) and in Federal rate cases (*see* Delegation Order No. 0204–33, December 21, 1978, 43 FR 60636, December 28, 1978). Both of these areas are currently under review by the Commission.

Some of this information in the Form No. 1 Federal filings has been found to supplement and duplicate data submitted for assessment of headwater benefits. The information is also used to supplement Federal rate filings, but is of very limited use in its present format.

The Commission, therefore, finds that the data currently filed by Federal entities pursuant to § 141.1 are not useful for the performance of its regulatory responsibilities and can be eliminated in their entirety.

Revisions to consolidate and standardize the headwater benefits and Federal rate filing requirements are expected in the next year, and may include data similar to that proposed for deletion herein. In the meantime, the Commission will continue to use current Federal rate and headwater benefits submissions, and specific data requests to obtain information needed for review in these areas.

The Energy Information Administration (EIA) may require the continued collection of the data herein proposed for deletion for itself or for some other sponsors within the Department of Energy. Another Federal agency could also require this data. If EIA or another agency should make such a determination during this rulemaking proceeding, the Commission would issue a Final Rule in this docket with a delayed effective date. This would provide the agencies a period of time in which to justify the need for the data and receive approval for the collection of this information under their own authority.

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[1] A Class A electric utility, licensee or other entity is one having annual electric operating revenues of $2,500,000 or more. A Class B electric utility, licensee or other entity is one having annual electric operating revenues of $1,000,000 or more but less than $2,500,000.

[2] In anticipation of this Notice of Proposed Rulemaking, the Commission issued on November 5, 1980 an Interim Rule to suspend, until further notice, the 1980 filing and future filings prescribed for Federal authorities by 18 CFR 141.1 (45 FR 74715, November 12, 1980).

[3] All references to the Federal filings of Form No. 1 in this Notice of Proposed Rulemaking include Form No. 1002.

III. Requested Comments

The Commission invites interested persons to submit written comments on this proposal. The Commission specifically requests that the comments address the following questions:

1. Does the proposed elimination of data affect any Commission regulatory functions?

2. Is there any reason for continued collection of this data by another Federal agency? Suggestions for the continued collection of data which have been proposed for elimination should identify the proper agency and the purpose for the proposed collection of the data.

IV. Comment Procedures

Interested persons wishing to comment on this proposal should submit copies of their comments to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM 81-3. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, January 29, 1981 will be considered by the Commission prior to promulgation of the Final Rule. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection during regular business hours in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(Federal Power Act, as amended, 16 U.S.C. §§ 792–828(c); Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission proposes to eliminate the requirement for Federal entities to file the "Form No. 1, Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)," including all modified versions of such Form No. 1, in accordance with 18 CFR 141.1., and to revise Part 141 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

Section 141.1 is amended in paragraphs (b) and (c) to read as follows:

§ 141.1 FPC Form No. 1, Annual Report for Electric Utilities, Licensees, and Others (Class A and Class B).

* * * * *

(b)(1) Each Class A electric utility, licensee, and other entity, *i.e.*, each corporation, person, or licensee as defined in section 3 of the Federal Power Act (16 U.S.C. 792, *et seq.*), including any agency, authority or other legal entity or instrumentality engaged in generation, transmission, distribution, or sale of electric energy, * * *

(2) This report form is not prescribed for any agency, authority or instrumentality of the United States, nor is it prescribed for municipalities as defined in section 3 of the Federal Power Act; *i.e.*, a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power.

(c)(1) Each Class B electric utility, licensee, and other entity; *i.e.*, each corporation, person, or licensee as defined in section 3 of the Federal Power Act, inlcluding any agency, authority or other legal entity or instrumentality engaged in generation, transmission, distribution or sale of electric energy, * * *

(2) This report form is not prescribed for any agency, authority or instrumentality of the United States, nor is it prescribed for municipalities as defined in section 3 of the Federal Power Act; *i.e.*, a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power.

* * * * *

¶ 32,105 High-Cost Gas Produced From Tight Formations (Louisiana-2)

46 F. R. 8568 (January 27, 1981).

18 CFR Part 271

High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the State of Louisiana Office of Conservation that the Haynesville Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on February 20, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on February 5, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Ting Chin, (202) 357–8595/John Bassett (202) 357–8589.

SUPPLEMENTARY INFORMATION:

Issued January 21, 1981.

I. Background

On December 31, 1980, the State of Louisiana Office of Conservation (Louisiana) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Haynesville Formation, located in the northwest part of the state of Louisiana, be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Louisiana's recommendation that the Haynesville Formation be designated a tight formation should be adopted. Louisiana's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation lies entirely within northern Bossier Parish, Louisiana, on the Arkansas border and is located in the southern portion of the Arkana Gas Field. (A more detailed description of the recommended area is contained in the recommendation on file with the Commission.) The Haynesville Formation is located below the Bossier Formation and above the Smackover Formation. The Haynesville Formation is defined as that formation occurring between the measured depths of 10,360 feet and 10,845 feet. In the Arkana Field, the Haynesville Formation consists of three members. The upper member is predominantly shale, 120 feet to 220 feet thick; the middle member is a sand 120 feet to 220 feet thick with shale stringers varying from 2 feet to 15 feet in thickness; and the lower member is 200 feet to 400 feet thick, consisting of shale and anhydrite.

III. Discussion of the Recommendation

Louisiana claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Louisiana on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Louisiana further asserts that the requirements of Statewide Order No. 29–B will assure that development of the Haynesville Formation will not adversely affect any fresh water aquifer that is or is expected to be used as a domestic or agricultural water supply. In addition, Louisiana states that it is in the process of establishing rules and regulations in accordance with the Environmental Protection Agency's Underground Injection Control guidelines which it believes will further prevent the contamination of any fresh water aquifer.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980 in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Louisiana that the Haynesville Formation, as described and delineated in Louisiana's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before February 20, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Louisiana-2), and should give reasons, including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than February 5, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432.)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Louisiana's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (28) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the

designated tight formations is located in the Commission's official file for Docket No. RM79–76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(17) through (27) [Reserved]

(28) *Haynesville Formation in Louisiana.* RM79–76 (Louisiana-2).

(i) *Delineation of formation.* The Haynesville Formation is found in the northern portion of Bossier Parish, Louisiana on the Arkansas border.

(ii) *Depth.* The top of the Haynesville Formation is located at a depth of 10,360 feet and the base is located at 10,845 feet. In the Arkana Field, the Haynesville Formation consists of three members. The upper member is predominantly shale, 120 feet to 220 feet thick; the middle member is a sand, 120 feet to 220 feet thick with shale stringers varying from 2 feet to 15 feet in thickness; and the lower member is 200 feet to 400 feet thick, consisting of shale and anhydrite.

¶ 32,106 Application for License for Minor Water Power Projects and Major Water Projects 5 Megawatts or Less

46 F. R. 9637 (January 29, 1981).

18 CFR Parts 4, 16, 131, and 375

[Docket No. RM81-10]

Application for License for Minor Water Power Projects and Major Water Projects 5 Megawatts or Less

January 21, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission proposes to adopt regulations governing so-called "short-form" applications for license for minor water power project and any water power project with an installed generating capacity of 5 megawatts or less. The requirements in the Commission's existing regulations are clarified by these regulations and the threshold installed capacity requirement for use of the short-form application is raised. This rulemaking is designed to expedite hydropower development by easing the burden of preparing an application for license and by assisting the Commission in more rapid processing of applications.

DATE: Written comments not later February 27, 1981.

ADDRESS: Office by the Secretary, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Ronald Corso, Office Electric Power Regulation, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426, 202-376-9171

Philip Leber, Office of The General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426, 202-357-5514

James Hoecker, Office of The General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426, 202-357-9342

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) proposes to amend the regulations governing applications for licenses under Part I of the Federal Power Act (Act) for water power projects with an installed generating capacity of 5 Megawatts (MW) or less. The proposed rule would revise §§ 4.31, 4.50, 4.51, 16.12, 131.6, and 375.308 of the Commission's regulations.

1. Background.

On September 5, 1978, the Commission initiated the first phase of a program to revise its regulations to simplify and expedite hydropower licensing by adopting regulations governing so-called "short-form" application for license.[1] Since that time the Commission has promulgated four rulemakings which revise its regulations governing hydropower licensing in order to reduce the burden on hydropower license applicants.[2]

The Commission has determined that further changes in the abbreviated license application requirements would expedite hydropower development. The rules proposed in this notice are

[1] Order No. 11, "Regulations Governing Applications for Shortform License (Minor)" (Docket No. RM78-9), issued September 5, 1978, 43 FR 40215, September 11, 1978.

[2] *See* Commission Order No. 59, "Regulations Governing Applications for License for Major Projects—Existing Dam" (Docket No. RM79-36), issued December 16, 1979, 45 FR 75383, December 20, 1979;

Order No. 76, "Exemptions of Small Conduit Hydroelectric Facilities from Part I of the Federal Power Act" (Docket No. TM79-35), issued April 18, 1980, 45 FR 28085, April 28, 1980; and

Order No. 106, "Exemption from All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less" (Docket No. RM80-65), issued November 7, 1980, 45 FR 76115, November 18, 1980.

designed to simplify the regulations and bring them into general conformance with other recent revisions to license application regulations. Specifically, the exhibits required as attachments to the application have been redesignated as Exhibit E (Environmental Report), Exhibit F (project drewings), and Exhibit G (maps). The Environmental Report has been revised slightly to be consistent with the report required under the Commission's rule governing case-by-case procedures for exempting small hydroelectric power projects from all or part of Part I of the Act.[3]

Most important, the proposed rules would expand the applicability of the abbreviated application regulations to include all projects with an installed generating capacity of 5 megawatts or less, including all minor water power projects and certain major water power projects.[4] The Commission recognizes that major projects that have at the time of application no dam or impoundment previously constructed, and major projects at existing dams which involve construction or operational changes that would significantly increase the maximum surface area or elevation of an existing impoundment will usually result in different and more substantial environmental impacts than will other major water power projects with between 1.5 and 5 megawatts of installed capacity. The Commission will therefore require any application for license for a major unconstructed or so-called major modified project with an installed capacity between 1.5 MW and 5 MW to include an Environmental Report under § 4.41(f); the abbreviated application requirements would otherwise remain applicable to all projects under 5 megawatts.

II. Initial Regulatory Flexibility Analysis for Docket Nos. RM81-10 and RM80-39

This small entity impact analysis is prepared pursuant to the Regulatory Flexibility Act (RFA),[5] which requires certain statements, descriptions, and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities." These RFA requirements apply only to generic rules for which a notice of proposed rulemaking is issued on or after January 1, 1981. The broad purpose of the RFA is to ensure more careful and informed agency consideration of rules that may significantly affect small business and small government entities, and to encourage cost-benefit analyses of these rules as well as the agency's consideration of alternative approaches that may better resolve any unnecessarily costly or adverse effects on these small entities.

In the preambles to both the proposed rule in this docket and the proposed rule governing applications for license for major unconstructed and major modified water power projects,[6] the Commission has presented its reasons for those agency actions, its objectives and the legal basis for the rulemakings, and the reporting, recordkeeping, and other compliance requirements which they impose, in accordance with the requirements of section 603(b) (1), (2), and (4) of the RFA. In sum, the proposed

[3] See § 4.107(e)(Exhibit E).

[4] The Commission and its predecessor, the Federal Power Commission, have maintained a distinction between "major" and "minor" projects based on section 10(i) of the Federal Power Act. That provision permits waiver of some provisions or requirements of the Act for projects with not more than 2000 horsepower or 1.5 megawatts of installed capacity. Such waiver is manifested in the kinds of conditions contained in licenses for projects above ("major") and below ("minor") the 1.5 megawatt demarcation. *See* § 2.9. The "short-form" license application procedures now set forth in § 131.6 have been previously applied only to minor projects. Under this proposed rule, those procedures would also apply (with the exception of an Exhibit E for unconstructed projects) to major projects with an installed capacity of 5 megawatts or less. However, section 10(i) will continue to permit the less stringent conditions only in licenses for minor projects. For purposes of providing exemption from all or part of Part I of the Act, all water power projects that are located at existing dams and have an installed capacity of 5 megawatts or less are called "small hydroelectric power projects." *See* §§ 4.101 through 4.112 of the Commission's regulations.

[5] 5. U.S.C. 601-612 (Pub. L. 96-354).

[6] "Regulations Governing Application for License for Major Unconstructed Projects and Major Modified Projects; Application for License for Transmission Line Only; and Application for Amendment to License" (Docket No. RM80-39), issued January, 1981.

rules constitute part of the Commission's program under section 405 of PURPA to provide simplified and espeditious licensing procedures for small water power projects, consistent with the Federal Power Act and other applicable laws. Although the rules deal with two distinct categories of projects, their common objective is to ease the burden of applying for a license, particularly for those projects with a coparatively small installed capacity. This objective is accomplished by clarifying and consolidating the exhibits that must be filed and by extending the benefits of so-called "short-form" application procedures from licenses for projects of 1.5 megawatts or less to licenses for any water power project with an installed capactiy of 5 megawatts or less. The Commission believes that while these changes will have a significant impact of small hydroelectric facilities, and consequently upon small businesses and small governmental entities that build, own, and operate many of them, the impact is a beneficial one that will reduce their regulatory and compliance costs.

Section 603(b)(3) of the RFA requires a description, and, if possible, an estimate of the number of small entities subject to the proposed rule. Historically, applications for license for the king of water power projects that would be covered by the procedures proposed in this docket number approximately 150 each year. Of these applications, possibly 75 percent are filed by entities that qualify as "small entities", including, within the meaning of the RFA, municipalities under 50,000 population. The Commission receives annually between 10 and 15 applications for licenses for major unconstructed water power projects that would be covered by the rule in docket No. RM80-39. Between 50 per cent and 60 per cent of these applicants are "small entities", including municipalities. Hence, the greatest simplification of the application procedures is proposed for those projects for which small entities most frequently seek licenses.

Section 603(c) of the RFA requires a description of significant alternatives to the proposed rule that may help minimize the proposal's adverse economic impact on small entities. From the viewpoint of regulatory flexibility, the significant alternatives to the proposed rules are to leave the existing provisions intact or to further simplify the licensing regulations. The first alternative would contradict the objectives of the Regulatory Flexibility Act. With respect to the second alternative, the Commission will continue to explore ways of easing the regulatory burdens on all regulated entities consistent with its responsibilities under existing law.

In particular, the Commission notes that the major purpose of these proposals, especially RM80-10, is to "establish differing compliance * * * requirements * * * that take into account the resources available to small entities," and to "clarify, consolidate, or simplify compliance and reporting requirements * * * for small entities"—precisely the approach which the RFA seeks to encourage.[1] One further alternative is possible: two kinds of short-form license applications for 5 megawatts and smaller facilities could be established—one for applications filed by "small entities" within the meaning of the RFA, and another for applications filed by larger entities. But the Commission does not believe this represents a sensible approach. It would create an unnecessary multiplicity of license application forms for projects 5 megawatts and smaller, and result in an undesirable proliferation of categories that would complicate, not simplify, hydroelectric regulation. In any event, the cost and time benefits of the short-form procedures should be equally available to all entities, small and large, which seek these licenses.

[1] 5 U.S.C. 603(c) (1) and (2).

In compliance with section 603(b)(4) of the RFA, the reporting and filing requirements of this proposed rule are set forth in Section III of this preamble. In further compliance with section 603(b)(4), the Commission notes that expertise in legal, environmental, and hydroelectric engineering matters would be required to satisfactorily comply with this proposed rule's filing requirements.

Finally, in compliance with section 609 of the RFA, the Commission notes that advance references to, and descriptions of, the proposed rules in both Docket Nos. RM81-10 and RM80-39 have been included within past editions of the Commission's Rulemaking Calendar which is published every three months and circulated to well over 1,000 individuals, companies, and agencies, including the Small Business Administration's Office of Advocacy.

III. Summary of the Proposed Regulations

Applicability and Definitions. § *4.60*

This section states that §§ 4.60 and 4.61 apply to any application for either an initial or new license for a water power project with an installed generating capacity of 5 megawatts or less. The section defines "minor water power project," "new license," and "initial license." Under § 4.50(a) and § 4.40(a), as revised in Docket No. RM80-39, an applicant for a major project with an installed capacity of 5 megawatts or less must use the abbreviated application requirements provided in §§ 4.60 and 4.61.

Contents of Application. § *4.61*

This section contains the specific regulations governing the contents of the abbreviated application for license for water power projects with a total installed generating capacity of 5 megawatts or less. The requirements are embodied in the general instructions, an initial statement, and three lettered exhibits.

(a) *General instructions.* The general instructions prescribe the number of copies of the application that must be filed with the Commission, and explain the level of detail required of the applicant in describing the project. The applicant is required to consult with appropriate Federal, State, and local agencies with expertise in environmental matters and submit with its abbreviated application for license documentation of or a summary of the consultation process.

(b) *Initial statement.* The initial statement provides basic information, including the nature of the application, the names, addresses, and telephone numbers of the applicant and its authorized agents, the nature of the applicant, and the name and location of the project. Information regarding the project description, purposes, and construction dates is required, together with a list of any public lands or reservations affected by the project, and a copy of the applicant's water quality certificate or a copy of a letter from the applicant to the appropriate agency requesting the certification.

(c) *Exhibit E.* This exhibit provides a report on the environmental resources of the project and the impacts of the project on those resources. Applicants for license of unconstructed or modified projects between 1.5 megawatts and 5 megawatts ("major") must file an Environmental Report as required under the Commission's regulations governing major unconstructed projects and major modified projects.[8] Applicants for license for projects with an installed capacity of 1.5 megawatts or less and for most major projects at existing dams must file a less extensive Environmental Report, as outlined in the proposed Exhibit E. The more stringent requirements are necessary for major unconstructed and major modified projects because there are greater impacts associated with the construction of dams and the creation of impoundments, or any subsequent

[8] *See* § 4.41(f) of Docket No. RM80-39.

significant increase in the size of an impoundment.

The environmental report is required to contain a description of the steps taken by the applicant in consulting with Federal, state, and local natural resources agencies, and the applicant must furnish copies of any letters containing the comments of those agencies.

(d) *Exhibit F.* This exhibit consists of general design drawings of the principal project works. The drawings must show a plan, elevation, profile, and section of the dam structure and powerplant, but the drawings need not conform to the specifications of § 4.32 of the Commission's regulations. Instead, the exhibit must be a simple drawing, and may be displayed on smaller sheets.

(e) *Exhibit G.* The final exhibit is a map of the project. The map need not conform to the specifications of § 4.32. If the project is proposed to have an installed capacity of 1.5 MW or less, and will not occupy any public lands or reservations, a definitive project boundary need not be shown. All other projects must include a project boundary defined by contours, courses, and distances, or a public land survey, depending upon the project works involved.

IV. Other Proposed Amendments to the Regulations

In addition to the described amendments to §§ 4.60 and 4.61, the Commission proposes further changes to the existing regulations. Section 4.31 would be amended to reflect the nomenclature in §§ 4.60 and 4.61. In the proposed rulemaking in Docket No. RM80-39, § 4.50(a) which now defines the applicability of the major project—existing dam regulations is proposed to require use of the abbreviated application for license for any such project with a generating capacity of not more than 5 megawatts.

Section 16.12 would be revised to reflect the nomenclature of §§ 4.60 and 4.61. Section 131.6, which prescribes the existing abbreviated application for license, would be revoked, since the proposed rule contains a new application format that obviates § 131.6. Finally, § 375.308 would be revised to omit the reference to § 131.6.

V. Written Comment Procedures

The Commission invites interested persons to submit written comments on the matters proposed in this notice. An original and 14 copies of such comments must be filed with the Commission not later than February 27, 1981. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. All comments should refer to Docket No. RM81-10.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426. the Commission will consider all timely comments before acting on the matters proposed in this notice.

(Federal Power Act, as amended, (16 U.S.C. 782-828c); Public Utility Regulatory Policies Act of 1978, (16 U.S.C. 2601-2645); the Department of Energy Organization Act, (42 U.S.C. 7101-7352; E.O. 12209), 3 CFR 142 (1978))

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

PART 4—LICENSES, PERMITS, EXEMPTIONS, AND DETERMINATIONS OF PROJECT COSTS

Part 4 is amended in the Table of Contents by revising Subpart G to read as follows:

* * * * *

Subpart G—Application for License for Minor Water Power Projects and Major Water Power Projects 5 MW or Less

Sec.

4.60 Applicability and definitions.

4.61 Contents of application.

* * * * *

2. Subpart G (§§ 4.60 and 4.61) is revised to read as follows:

Subpart G—Application for License for Minor Water Power Projects and Major Water Power Projects 5 MW or Less

§ 4.60 Applicability and Definitions.

(a) *Applicability.* The provisions of §§ 4.60 and 4.61 apply to any application for an initial license or a new license for:

(1) A minor water power project, as defined in paragraph (b) of this section;

(2) Any major project—existing dam, as defined in § 4.50(b)(5), that has a total installed capacity of 5 megawatts or less; or

(3) Any major unconstructed project or major modified project, as defined in § 4.40 (b)(2) and (3), that has a total installed capacity of 5 megawatts or less.

(b) *Definitions.* For the purposes of this subpart:

(1) "Initial license" means the first license issued for a water power project under either the Federal Water Power Act of 1920 or the Federal Power Act;

(2) "New license" means any license for a water power project that is issued under the Federal Power Act after the initial license for that project, except an annual license issued under Section 15 of the Federal Power Act; and

(3) "Minor water power project" means any licensed or unlicensed, existing or proposed water power project that, as proposed to be licensed, would have a total installed generation capacity of 2000 horsepower, 1.5 megawatts, or less.

(c) *Notice to agencies.* For any water power project 5 megawatts or less, Federal, state, and local agencies will be notified and requested to comment on the application by the Commission only through the public notice procedure. Copies of the application will be available for inspection at the Commission's Office of Public Information, and agencies may request additional copies of the application from the applicant.

§ 4.61 Contents of application.

(a) *General Instruction*—(1) *Consultation.* Each application for license for a water power project with an installed capacity of 5 megawatts or less must be prepared after consultation with appropriate Federal, state and local agencies with expertise in environmental matters. Information from the consultation process must be included in the applicant's Exhibit E, as appropriate. Such agencies are to be given the opportunity to comment on the proposed project prior to filing of the application. A list of agencies to be consulted can be obtained from the Director of the Commission's Division of Hydropower Licensing.

(2) *Copies and appendix.* (i) This application is to be completed and filed in an original and fourteen copies with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426, and a copy must be served at the same time on the Commission's regional engineer for the region in which the project is located, and on each of the agencies consulted under subparagraph (1) of this paragraph.

(ii) The applicant must attach to the application as an appendix, either:

(A) A copy of a water quality certificate as described in Section 401 of the Federal Water Pollution Control Act (also known as the Clean Water Act, 33 U.S.C. 1341), or an agency statement that such certification is waived; or

(B) A copy of a dated letter from the applicant to the appropriate agency requesting that certification.

(3) *Entry upon land.* No work may be started on the project until receipt of a signed license from the Commission. Acceptance of an application does not authorize entry upon public lands or reservations of the United States for any purpose. The applicant should determine whether any Federal, state, or local permits are required.

(4) *Project description.* The project description must include, in tabular form if possible, as appropriate:

(i) The number of generating units, including auxiliary units, the capacity of each unit, and provisions, if any, for future units;

(ii) The type of hydraulic turbine(s);

(iii) A description of how the plant is to be operated, manual or automatic,

and whether the plant is to be used for peaking;

(iv) The estimated average annual generation in kilowatt-hours or mechanical energy equivalent;

(v) The estimated average head on the plant;

(vi) The reservoir surface area in acres and, if known, the net and gross storage capacity;

(vii) The estimated hydraulic capacity of the plant (flow through the plant) in cubic feet per second and estimated average flow of the stream or water body at the plant or point of diversion; for projects with installed capacity of more than 1.5 megawatts a flow duration curve and a description of the drainage area for the project site must be provided;

(viii) Sizes, capacities, and construction materials, as appropriate, of pipelines, ditches, flumes, canals, intake facilities, powerhouses, dams, transmission lines, and other appurtenances; and

(ix) The estimated cost of the project.

(5) Exhibits F and G must be submitted on separate drawings. Drawings for Exhibits F and G must have identifying title blocks and bear the following certification: "This drawing is a part of the application for license made by the undersigned this —— day of ————, 19 —."

(6) Each application for a license for a water power project 5 megawatts or less must include an initial statement and lettered exhibits described by paragraphs (b) through (e) of this section. The Commission reserves the right to require additional information, or another filing procedure, if data provided indicate such action to be appropriate.

(b) *Initial Statement.*

Before the Federal Energy Regulatory Commission

Application for License for a [Minor Water Power Project, or Major Water Power Project, 5 Megawatts or Less, as Appropriate]

(1) ———— (Name of Applicant) applies to the Federal Energy Regulatory Commission for ———— (license or new license, as appropriate) for the ———— (name of project) water power project, as described hereinafter. (Specify any previous FERC project number designation.)

(2) The location of the project is:
State or territory ————
County ————
Township or nearby town ————
Stream or other body of water ————

(3) The exact name, address, and telephone number of the applicant are:
————
————
————

(4) The exact name, address, and telephone number of each person authorized to act as agent for the applicant in this application, if applicable, are:
————
————
————

(5) The applicant is a ———— (citizen of the United States, association of citizens of the United States, domestic corporation, municipality, or State, as appropriate).

(6) Project description and proposed mode of operation, with reference to Exhibits F and G, as appropriate (see General Instruction #4).

(i) Proposed installed generating capacity ——— MW.

(ii) Check appropriate box:
☐ existing dam ☐ unconstructed dam
☐ existing dam, major modified project (see § 4.40(b)(3))

(7) Lands of the United States affected (shown on Exhibit G):

	Name	Acres
(i) National Forest		
(ii) Indian Reservation		
(iii) Public Lands Under Jurisdiction of		
(iv) Other		
(v) Total U.S. Lands		
(vi) Check appropriate box: ☐ Surveyed land ☐ Unsurveyed land		

(8) Purposes of project (for example; use of power output).

(9) Construction of the project is planned to start within ——months, and is planned to be completed within —— months, from the date of issuance of license.

(10) This application is executed in the State ————
County of ————ss:
By: ————

(Name and Address)
————
————

being duly sworn, depose(s) and say(s) that the contents of this application are true to the best of —— (his or her) knowledge or belief.

The undersigned applicant(s) has (have) signed this application this ——day of ——, 19—.
[Applicant(s)] ——————————
By: ——————————
Subscribed and sworn to before me, a [Notary Public, or title of other official authorized by the state to notarize documents, as appropriate] of the State of ——————, this ——— day of ——————, 19—.
SEAL/ [if any]
——————————
(Notary Public, or other authorized official)

(c) *Exhibit E* is an environmental report. The report should be consistent with the scope of the project and the environmental impacts of the proposed action.

(1) *For major unconstructed and major modified projects, 1.5 to 5 MW.* The Application must contain an Exhibit E conforming with the requirements of § 4.41(f) of this chapter if the application is for license for a water power project which has, or is proposed to have, a total installed generating capacity greater than 1.5 MW but not greater than 5 MW, and which:

(i) Would use of the water power potential of a dam and impoundment which, at the time of application, has not been constructed (*see* § 4.40(b)(2)); or

(ii) Involves any repair, modification or reconstruction of an existing dam that would result in a significant change in the normal maximum surface area or elevation of an existing impoundment or involves any change in existing project works or opeations that would result in a significant environmental impact (*see* § 4.40(b)(3)).

(2) *For minor projects and projects at existing dams, 5 MW or less.* If the application is for license for any minor water power project with a total proposed installed generating capacity of 1.5 MW or less, or any major project—existing dam with a proposed installed capacity of 5 MW or less, the application must contain an Exhibit E that contains:

(i) A description of the environmental setting of the project, including vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational uses, historical and archeological resources, and scenic and aesthetic resources. The report must include a discussion of endangered or threatened plant and animal species, any critical habitats, and any sites eligible for or included on the National Register of Historic Places. The applicant may obtain assistance in the preparation of this information from state natural resources agencies, the state historic preservation officer, and from local offices of Federal natural resources agencies.

(ii) A description of the expected environmental impacts from proposed construction or development and the proposed operation of the power project, including any impacts from any proposed changes in the capacity and mode of operation of the project if it is already generating electric power, and an explanation of the specific measures proposed by the applicant, the agencies, and others to protect and enhance environmental resources and values and to mitigate adverse impacts of the project on such resources. The applicant must explain its reasons for not undertaking any measures proposed by any agency consulted.

(iii) A description of the steps taken by the applicant in consulting with Federal, state, and local agencies with expertise in environmental matters during the preparation of the environmental report prior to its filing with the Commission. In its report, the applicant must:

(A) Indicate which agencies were consulted during the preparation of the environmental report and provide copies of letters or other documentation showing that the applicant consulted or attempted to consult with each of the relevant agencies (specifying each agency) before filing the application, including any terms or conditions of license that those agencies have determined are appropriate to prevent loss of, or damage to, natural resources;

(B) List those agencies that were provided copies of the application as filed with the Commission, the date or dates provided, and copies of any letters that may be received from agencies

commenting on the application; and

(iv) Any additional information the applicant considers important.

(3) *Time for Consultation.* If any agency that an applicant is required under paragraph (a)(1) of this section to consult when preparing an application fails to provide the applicant with documentation of the consultation process within a reasonable time, in no case less than 30 days after such documentation is requested, the applicant may submit a summary of the consultation and any recommendations of the agency.

(d) *Exhibit F* consists of general drawings of the principal project works. The drawings need not conform to the specifications of § 4.32. The exhibit must instead conform to the following requirements:

(1) The exhibit must consist of simple ink drawings, or drawings of similar quality, on sheets no smaller than 8 and one-half inches by 11 inches, drawn to a scale no smaller than 1 inch equals 50 feet for plans, elevations, and profiles, and 1 inch equals 10 feet for sections. After initial review of the application, an original and 2 copies of any drawing must be submitted on 35mm microfilm, if requested by Commission staff.

(2) The drawings must show a plan, elevation, profile, and section of the dam structure and powerplant. Generating and auxiliary equipment proposed must be clearly and simply depicted and described. Include a north arrow on the plan view.

(e) *Exhibit G* is a map of the project. The map need not conform to the specifications of § 4.32. The exhibit must instead conform to the following requirements:

(1) The exhibit is a map or maps that must show the location of all project works and their location in relation to the stream or other water body on which the project is located and to the nearest town or any permanent monuments or objects, such as roads, transmission lines, or other structures, that can be noted on the map and recognized in the field. In the case of unsurveyed public land, or land that is not public land, give the best legal description available. If surveyed land, provide sections, subdivisions, range and township, and principal base and meridian.

(2) The map must consist of ink drawings or drawings of similar quality on sheets no smaller than 8 and one-half inches by 11 inches and not larger than 24 inches by 36 inches, drawn to a scale no smaller than one inch equals 1,000 feet. After review of the application, the applicant must submit an original of the map(s), if requested by Commission staff. Each original map must consist of a print on silver or gelatin 35mm microfilm mounted on Type D (3¼" × 7⅜") aperture cards. Two duplicates of each original must also be submitted at that time.

(3) If the project is proposed to have an installed capacity of 1.5 MW or less, and will not occupy any public lands or reservations of the United States, a definitive project boundary need not be shown. The map should provide a reasonably accurate depiction of the project location and all project works. If any project 1.5 megawatts or less would occupy public lands, the definitive project boundary need only be shown on such U.S. lands or reservations.

(4) Water power projects not excepted by subparagraph (3) of this paragraph must include a project boundary as follows:

(i) The project boundary must enclose all project works, such as the dam, reservoir, pipelines, roads, powerplant, access roads, and transmission lines. The boundary must be set at the minimum feasible distance from project works necessary to allow operation and maintance of the project and control of the shoreline and reservoir. The project boundary may be contour elevation lines, specified courses and distances, or lines upon or parallel to public land survey lines.

(ii) The project boundary must be depicted on the map by use of contour lines (preferred method), courses and distances, public land survey or lines parallel to the lines of the survey, or any combination of those methods for reservoirs and impoundments, and the project boundary around dams,

spillways, and powerhouses; and must be depicted by specified distances from a surveyed center line or offset lines of survey for continuous features such as access roads, transmission lines, pipelines, or canals. A tape-compass survey is acceptable for determining courses and distances.

(iii) The area of public lands or reservations within the project boundary must be shown in acres. The appropriate Federal agency should be contacted for assistance in determining the acreages.

(iv) For clarity, use inset sketches to a larger scale than that used for the overall map to show relationships of project works, natural features, and property lines.

(v) Show one or more ties by distance and bearing from a definite, identifiable point or points on project works or the project boundary to established corners of the public land survey or other survey monuments, if available.

(vi) If the project affects unsurveyed Federal lands, the protraction of township and section lines must be shown. Such protractions, whenever available, must be those recognized by the agency of the United States having jurisdiction over the lands. On unsurveyed lands, show ties by distance and bearing to fixed recognizable objects.

3. Section 4.31 is amended by revising paragraph (a)(2)(ii) to read as follows:

§ 4.31 Acceptance for filing or rejection.

(a) Each application for a preliminary permit or license must:

* * * * *

(2) Contain the information and documents prescribed in the following sections of this chapter, according to the type of application:

* * * * *

(ii) License for a minor water power project and major water power projects 5 megawatts or less: §§ 4.60 and 4.61.

* * * * *

PART 16—PROCEDURES RELATING TO TAKEOVER AND RELICENSING OF LICENSED PROJECTS

* * * * *

4. Part 16 is amended in the Table of Contents by revising § 16.12 to read as follows:

Sec.

16.12 Renewal of license for a minor water power project or for a minor part of a water power project not subject to sections 14 and 15 of the Federal Power Act.

* * * * *

6. Section 16.12 is revised to read as follows:

§ 16.12 Renewal of license for a minor water power project or for a minor part of a water power project not subject to sections 14 and 15 of the Federal Power Act.

A licensee whose minor water power project license or license for a minor part of a project is not subject to sections 14 and 15 of the Act, and who wishes to continue operation of the project after the end of the license term, must file an application for a "new license" not later than one year prior to the expiration of the original license, in accordance with § 4.31 of this chapter. Each application for new license under this section must conform to §§ 4.60 and 4.61 of this chapter.

PART 131—FORMS

§ 131.6 [Revoked and Removed]

6. Section 131.6 is revoked and removed.

PART 375—THE COMMISSION

7. Section 375.308 is amended by revising paragraph (c) to read as follows:

§ 375.308 Delegations to the Director of the Office of Electric Power Regulation.

* * * * *

(c) Take appropriate action on uncontested filings made in response to a term or condition in a preliminary

permit or license issued for a water power project, or in response to the requirements of an order of the Commission concerning a water power project, including:

(1) Acceptance and approval of new or revised exhibits in Part 4 of this chapter; and

(2) Acceptance and approval of any studies, plans, reports, maps, drawings, or specifications.

* * * * *

¶ 32,107 High-Cost Gas Produced From Tight Formations; Ceiling Prices (New Mexico-2)

46 F. R. 9962 (January 30, 1981).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-2)]

High-Cost Gas Produced From Tight Formations; Ceiling Prices

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of New Mexico Oil Conservation Division that the Atoka Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on February 25, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on February 10, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

SUPPLEMENTARY INFORMATION:

Issued: January 26, 1981.

I. Background

On January 15, 1981, the State of New Mexico Oil Conservation Division (New Mexico) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 *Federal Register* 56034, August 22, 1980), that the Atoka Formation located in Lea County, New Mexico be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New Mexico's recommendation that the Atoka Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with New Mexico's recommendation. New Mexico's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation lies entirely with Lea County, New Mexico and underlies an area located approximately 9 miles north of Lovington, New Mexico, approximately 15 miles west of the Texas State border, and approximately 3 miles southwest of Tatum, New Mexico. The recommended area contains approximately 37,760 acres. The vertical limit to the top of the Atoka Formation ranges from 11,500 to 12,450 feet and averages 12,200 feet. The vertical limit of the base of the Atoka Formation is defined by the top of the Morrow Formation. The Atoka Formation ranges from approximately 700 to 900 feet in thickness.

III. Discussion of Recommendation

New Mexico claims in its submission that evidence gathered through information and testimony presented at

a public hearing in Case No. 7085, convened by New Mexico on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

New Mexico further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 *Federal Register* 53456, August 12, 1980), notice is hereby given of the proposal submitted by New Mexico that the Atoka Formation, as described and delineated in New Mexico's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before February 25, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (New Mexico-2), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than February 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event New Mexico's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (29) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(17) through (28) [Reserved]

(29) *Atoka Formation in New Mexico.* (i) *Delineation of formation.* The Atoka Formation is found in Lea County, New Mexico. RM79–76 (New Mexico-2).

(ii) *Depth.* The Atoka Formation is defined as that formation, the depth to the top of which ranges from 11,500 to 12,450 feet and averages 12,200 feet, and the bottom of which is defined by the top of the Morrow Formation.

¶ 32,108 Application for License for Major Unconstructed Projects and Major Modified Projects; Application for License for Transmission Lines Only; and Application for Amendment to License

46 F. R. 10165 (February 2, 1981).

[Docket No. RM80-39]

18 CFR Parts 2, 4, 5, 16, and 131

Regulations Governing Application for License for Major Unconstructed Projects and Major Modified Projects; Application for License for Transmission Lines Only; and Application for Amendment to License

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to amend the regulations governing three kinds of licensing under Part II of the Federal Power Act (Act) for: (1) major water power projects that have an installed generating capacity greater than 1.5 megawatts and that would either utilize the water power potential of a dam that, at the time application is filed, is not constructed ("major unconstructed project") or that would change the state of existing project works so as to produce a significant increase in the normal maximum surface area or elevation of an impoundment or otherwise produce a significant envrionmental impact ("major modified project"); (2) only the transmission lines that transmit power from a licensed water power project or other hydroelectric project authorized by Congress to the point of junction with the distribution system or with the interconnected primary transmission system; and (3) any amendment to a license that would entail a change in the physical features, plans, mode of operation, or constuction period of project or its boundary.

The proposed rule would also make conforming changes in §§ 4.31, 16.7, 131.2, and Appendix A of Part 2 of the Commission's requirements. The proposed regulations would reorganize the license applications. The regulations are designed to ease the burden of preparing applications and to assist the Commission in processing applications for license. The rulemaking is therefore expected to expedite hydropower development.

DATE: Written Comments by March 27, 1981.

ADDRESS: Office of The Secretary, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Ronald Corso, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, Telephone 202-376-9171.

Phillip Leber, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, Telephone 202-357-5514.

James Hoecker, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20425, Telephone 202-357-9342.

Regulations Governing Applications for License for Major Unconstructed Projects and Major Modified Projects; Applications for License for Transmission Line Only; and Applications for Amendment to License; Proposed Rulemaking

Issued: January 23, 1981.

The Federal Energy Regulatory Commission (Commission) proposes to amend the regulations governing applications for license under Part I of

the Federal Power Act (Act) for: (1) major water power projects with an installed generating capacity greater than 1.5 megawatts (MW) that would either utilize the water power potential of a dam that, at the time application is filed, is not constructed ("major unconstructed project") or that would change the state of existing project works so as to produce a significant increase in the normal maximum surface area or elevation of an impoundment or otherwise produce a significant environmental impact ("major modified project"); (2) only the transmission lines that transmit power from a licensed water power or other hydroelectric project authorized by Congress to the point of junction with the distribution system or with the interconnected primary transmission system; and (3) any amendment to a license that would entail a change in the physical features, plans, mode of operation, or construction period of the project or its boundary.

The proposed rule would also make conforming changes in §§ 4.31, 4.50, 16.7, 131.2, and Appendix A of Part 2 of the Commission's regulations.

I. Background

This rulemaking is the third phase of a program of licensing reform for all projects within the Commission's jurisdiction built for the generation of electrical energy by means of water power. The first phase of this reform was instituted in 1978, when the Commission issued the so-called "short-form" application procedures for all "minor" projects, *i.e.*, those with a capacity of 1.5 MW or less.[1]

On October 22, 1979, the Commission issued rules which prescribe general filing requirements and evaluation procedures applicable to both preliminary permit and license applications, and which simplify the procedures for application for preliminary permits, amendments to permits, and cancellations of permits.[2]

On November 19, 1979, the Commission next issued rules that establish application procedures for licensing major projects which are located at existing dams and have a generating capacity of greater than 1.5 MS.[3]

The Commission has also issued related rules to encourage development of specialized kinds of hydroelectric facilities. It recently established procedures to exempt from all or part of Part I of the Act any small conduit hydroelectric facility that has a generating capacity of 15 MW or less.[4] Similarly, the Commission issued rules on November 7, 1980, setting forth procedures to exempt from all or part of Part I of the Act certain small hydroelectric projects having a proposed installed generating capacity of 5 MW or less.[5]

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[1] Order No. 11, "Regulations Governing Applications for Short-form License (Minor)" (Docket No. RM78-9), issued September 5, 1978, 43 Fed. Reg. 40215, September 11, 1978. The 1.5 MW capacity criterion was based on the fact that the Commission is authorized under Section 10(i) of the Act (16 U.S.C. § 803(i)) to give less intensive scrutiny to minor projects. The Public Utility Regulatory Policies Act of 1978 ("PURPA") (16 U.S.C. § 2705 et seq.) encourages development of small hydroelectric power projects with an installed capacity of 15 MW or less at existing dams. Among other measures, PURPA mandates simplified and expeditious licensing for such small water projects. The Energy Security Act of 1980 (94 Stat. 611) increases that capacity level to 30 MW. The first phase of the Commission's reforms therefore covered only a portion of the projects identified under PURPA.

[2] Order No. 54, "Regulations Prescribing General Provisions for Preliminary Permit and License Applications; and Regulations Governing Applications for Amendments to and Cancellation of Permits" (Docket No. RM79-23), issued October 22, 1979, 44 FR 61328, October 25, 1979.

[3] Order No. 59, "Regulations Governing Applications for License for Major Projects—Existing Dams" (Docket No. RM79-36), issued December 16, 1979, 45 FR 75383, December 20, 1979.

[4] Order No. 76, "Exemptions of Small Conduit Hydroelectric Facilities from Part I of the Federal Power Act" (Docket No. RM79-35), issued April 18, 1980, 45 FR 28085, April 28, 1980.

[5] Order No. 106, "Exemption from All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less" (Docket No. RM80-65), issued November 7, 1980, 45 FR 76115, November 18, 1980.

The existing requirements for the types of license applications which are affected by this rulemaking are located in various parts of Title 18 of the Code of Federal Regulations. Substantive requirements applicable to one or all of these applications may be found in §§ 2.80 and 2.81, Appendix A to Part 2, §§ 4.40, 4.41, 4.70, 4.71, 5.1 through 5.4, 16.7, 131.2, 131.3, and 131.4 of the Commission's regulations. A potential applicant faces the prospect of meeting information requirements embodied in up to 23 separate exhibits.

The proposed rules set forth in this notice are designed to ease the burden of compliance in several ways. First, they reduce the requested information that is needed for the Commission to carry out its duties under existing law in an informed and responsible manner.[6] For example, the provisions requiring extensive documentation of the nature of the applicant and its authority to file the application have been eliminated and requirements relating to evidence of compliance with state laws have been simplified.[7] This in no way relieves the applicant of the obligation comply with any applicable state law not preempted by Part I of the Act.

Second, the Commission has consolidated the requests for information according to related subject matter. All paragraphs and exhibits requesting information on environmental matters [8] have been consolidated into Exhibit E (Environmental Report), required under § 4.41(f). Rational organization of the requirements should reduce confusion and redundancy in the materials submitted.

Finally, the rules minimize the element of subjective interpretation in the Commission's requirements by reducing the requests for information, where possible, to simple, objective, descriptions of what is desired. The Commission believes that clearer, simpler requirements and a cooperative effort will help avoid the application deficiencies that have plagued the licensing program in the past.

Projects of the type covered by this rulemaking usually result in more significant environmental impacts than do water power projects at existing dams which do not entail significant construction or alteration of the impoundment level. Under the proposed rule, the Commission therefore requires of any applicant for a major unconstructed project or a major modified project an Environmental Report of considerably greater detail than it does for smaller projects or most projects at existing dams. In conjunction with this requirement, the Commission is revising its National Environmental Policy Act regulations which specify that any Environmental Report must be tailored to the size and type of water power project for which the applicant seeks a license.[9]

Under the proposed rule, an applicant for license of a project with an installed generating capacity of 5 megawatts or

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[6] Section 405 of PURPA (16 U.S.C. § 2705) provides that the Commission's simplified licensing procedures must be "consistent with the applicable provisions of law" and that no project covered by the procedures will be exempted from "any requirement applicable to any such project under the National Environmental Policy Act of 1969, the Fish and Wildlife Coordination Act, the Endangered Species Act, or any other provision of Federal Law."

[7] See existing §§ 4.40(b) and 4.41—Exhibits A–F. These requirements have been distilled to simple statements in the initial portion of the application under § 4.41(a). Since the entire application is subscribed and verified under § 1.16 of our rules, the statements themselves will suffice as evidence. Additional information will be requested in cases where it is needed.

[8] See existing §§ 2.80, 2.40(k) and (l), 4.41 (Exhibits H, R, S, V, and W, and Appendix A to Part 2.

[9] Sections 2.80 through 2.82, constituting most of the Commission's existing environmental review regulations, would be replaced under the rulemaking implementing the National Environmental Policy Act of 1969 (NEPA) in Docket No. RM79-69. These changes are intended to conform the Commission's regulations to the guidelines of the Council on Environmental Quality. Appendix A of Part 2 would be amended and transferred to new Part 380 under the same rulemaking. 44 FR 50052, August 27, 1979.

less may file under the Commission's abbreviated application procedures. The Commission is proposing in a companion rulemaking that abbreviated application procedures be applied to all projects with a total generating capacity of 5 MW or less.[10] However, this change would not alter the current requirement that a more extensive Environmental Report (Exhibit E) be filed for any major unconstructed or major modified project with an installed capacity in Excess of 1.5 MW.

II. Initial Regulatory Flexibility Analysis

The Commission's statement concerning the impact of this rulemaking on small entities is combined with the analysis of the proposed rulemaking governing minor water power projects in Docket No. RM81-10, issued as a companion to this rulemaking.

III. Summary of the Proposed Regulations

A. Major Unconstructed Projects and Major Modified Projects

§ *4.40 Applicability and definitions.* This section states that §§ 4.40 and 4.41 apply to any application for an initial license for a major unconstructed project, and an initial license or new license for a major modified project. Applications for license of major water power projects with an installed generating capacity of 5 MW or less must be filed under §§ 4.60 and 4.61 of the Commission's regulations. Section 4.40 defines "major unconstructed project", "major modified project", "initial license", and "new license", and offers the assistance of the Commission staff in determining whether §§ 4.40 and 4.41 apply to the applicant's proposed project.

§ *4.41 Contents of application.* This section describes the contents of an application for a license for a major unconstructed project or a major modified project. The rule requires applicants to consult with local, state, and Federal natural resource agencies prior to filing their applications for license. These regulations follow other Commission procedures by affording other agencies an opportunity to review the proposed development and to be part of the planning process before the application has been filed with the Commission. Otherwise, proceedings might often be delayed while agencies consider the effects of projects on their areas of responsibility and fashion recommendations. With pre-application consultation, key environmental issues will be identified and addressed at an earlier point in the process and the Commission's own required consultation with other agencies will be expedited.[11] The applicant must allow at least 60 days for each agency consulted to respond to the applicant's request for documentation of the consultation process. In addition, the Commission will supply to each such agency a copy of the completed application, as filed, in order to provide further opportunity for comment.

(a) *Initial statement.* The initial statement provides certain basic information necessary for identification and orientation purposes, including the nature of the application, the name, business address, and telephone number

[10] "Regulations Governing Applications for License for Minor Water Power Projects and Major Water Power Projects 5 Megawatts or Less," (Docket No. RM81-10), issued January 21, 1981.

[11] Several statutes, including PURPA, require the Commission to consult with other agencies. Section 405 of PURPA provides that, prior to issuing a license for a project which fits the PURPA criteria, the Commission must "provide opportunity for consultation with the Council on Environmental Quality and the Environmental Protection Agency with respect to the environmental effects of such project." This duty will be carried out in accordance with our established procedures for consultation during the license application review process. Moreover, in certain circumstances, other agencies may have concurrent jurisdiction with respect to authorization of a project. Prior consultation by applicants will facilitate coordination with these other agencies. *See* section 10(c) of the Act, 16 U.S.C. § 803(c).

of the applicant and its authorized agents, the nature of the applicant, and the name and location of the project. The applicant is also required to state that it has complied with the laws of the state where the project is located with respect to obtaining property rights and the rights to appropriate, divert, and use water for power purposes, and with respect to obtaining authorization to engage in the business of producing, transmitting, and distributing power, and any other business necessary to accomplish the purposes of the requested license.[12]

(b) *Exhibit A.* This exhibit provides a description of the physical structures and features of the project. If the project includes more than one dam and associated facilities, each such discrete development must be described separately. The exhibit also includes a tabulation of any lands of the United States that are enclosed within the project boundary. This tabulation is necessary in order to record accurately the lands which have been reserved from entry, location, or other disposal pursuant to section 24 of the Act, 16 U.S.C. 818.

(c) *Exhibit B.* A statement of project operation and resource utilization is provided by this exhibit. The exhibit calls for a description of the available water supply and technical documentation of the manner in which the applicant proposes to utilize that water supply for the generation of power. The applicant must also explain how it intends to sell the power. Finally, the applicant must describe any plans it has for future hydro-electric development on the affected stream. The information in this exhibit will assist the Commission in determining whether the applicant's existing or proposed development and operation comport with optimum development of the waterway, as required by section 10(a) of the Act, 16 U.S.C. 803(a).

(d) *Exhibit C.* The third exhibit provides a proposed construction schedule for new construction on the project and a construction history for existing project works, including the dates of commencement and completion of construction and the date of first commercial operation.

(e) *Exhibit D.* This exhibit provides a statement of costs and financing. If the applicant seeks a new license for a proposed change in the existing state of project works or project operations which would result in a significant increase in the normal maximum surface area of elevation of an existing impoundment, and is not a municipality or a state, it must provide an estimate of the amount that would be payable (net investment) if the United States exercised its right to take over the project upon expiration of the license pursuant to section 14 of the Act, 16 U.S.C. § 807.

If the applicant seeks an initial license, and any portion of the proposed project consists of previously constructed, unlicensed water power structures or facilities, a statement of the original cost of those project works and the corresponding land and water rights must be provided. The Commission is required by section 4(b) of the Act, 16 U.S.C. § 797(b) to obtain information on the original cost of a project, in order to determine the economic viability of the project and the quality of the applicant's plan.

Estimated costs of any proposed new development and estimated annual costs must also be provided, as well as information concerning the value of project power to the applicant and the sources and extent of financing and annual revenues available to meet the estimated costs. This information would enable the Commission to assess the economic and financial viability of the project.

(f) *Exhibit E.* This exhibit provides a report on the environmental resources of the project, the impacts of the project on those resources, the proposed measures to mitigate the impacts or to protect and enhance the resources, and an

[12] *See* section 9(b) of the Act, 16 U.S.C. § 802(b).

environmental assessment of alternative sites, facility designs, and energy options. The information required is more detailed and extensive than the information required by the existing regulations governing applications for major projects—existing dams.[15] The more stringent requirements are justified on the basis that there are greater impacts associated with the construction of dams and the creation of impoundments, or any significant modification of an existing dam which would increase the maximum surface area or elevation of the impoundment or otherwise cause a significant environmental impact.

The Environmental Report contains a general description of the environment of the proposed project area and detailed analysis of water use and quality; fish, wildlife, and botantical resources; historic and archaeological resources; socio-economic impacts; geological and soil resources; recreational resources; aesthetic resources; and, land uses.

An applicant must explain why it considers any measures proposed by any agency consulted not to be appropriate.

(g) *Exhibit F.* This exhibit consists of general design drawings of the principal projects works. The drawings must show plans, elevations, profiles, and sections for each structure, and must be accompanied by sufficient information concerning structural strength and stability and other controlling factors to demonstrate that the structures are safe and adequate for their stated functions.

The applicant may file either preliminary of final design drawings with the application, and five copies of a supporting design report must accompany the drawings, describing the basis for the design depicted in the design drawings. The supporting design report must include design assumptions and the result of all design analyses in sufficient detail for staff to make an independent assessment of the safety and adequacy of the proposed project works.

(h) *Exhibit G.* The final exhibit is a map of the project. The map must show the geographical location of the project, the physical interrelationships of project works and other features, a project boundary enclosing the project purposes, and any lands of the United States that are within the project boundary.

B. Transmission Lines

Sections 4.70 and 4.71, governing applications for license for transmission lines only, would be revised to direct applicants to use the exhibits provided in § 4.41 or § 4.61, depending upon the installed generating capacity of the project served by the transmission line and whether the line is constructed at the time of a license application. All applications for license for transmission line only must include an initial statement indicating the name and address of the applicant, the name of the project to which the transmission line will be connected, and the proposed market for the power.

An application for license of any unconstructed transmission line connected to a water power project with an installed capacity of more than 5 MW must include the exhibits required under § 4.41, to the extent that those requirements ar appropriate to transmission lines. Applications for license for any line that is already constructed or that is unconstructed but proposed to be connected to a project with a capacity of 5 MW or less must include the short-form exhibits required under § 4.61, to the extent that those requirements are appropriate to transmission lines.

C. Amendment of License

Sections 5.1 through 5.4 would be revoked, and the regulations governing applications for amendment of a license would be transferred to a new subpart of Part 4 of the regulations. Under new Subpart L, all applications for

[15] *See* § 4.51(f) of the Commission's regulations.

amendment of a license must include an initial statement indicating the name, address, and telephone number of the applicant, a description of the proposed changes, and the reasons for the changes. Subpart L then refers applicants to § 4.41, 4.51 or 4.61, depending upon the installed generating capacity of the project and whether or not the dam and impoundment are constructed at the time the application is filed.

An application for amendment of a license for a major unconstructed or major modified project must include the exhibits required under § 4.41. An application for amendment of a license for a major project—existing dam must include the exhibits required under § 4.51. Lastly, an application for amendment of a license for a minor hydroelectric power project must include the exhibits required under § 4.61, but if the project is between 1.5 MW and 5 MW at the site of a dam proposed to be constructed after the issuance of the amendment, the application must include an Environmental Report (Exhibit E) from § 4.41.

III. Other Proposed Changes and Deletions

In addition to the described amendments to §§ 4.40, 4.41, 4.70, 4.71, and 5.1 through 5.4, the Commission proposes further changes to the existing regulations. Section 4.50, which defines the applicability of the major project—existing dam regulations, would be amended to indicate that §§ 4.50 and 4.51 do not apply to those projects that fall within the category of major modified projects. The proposed Phase III regulations govern such projects and are referenced in § 4.50(a). Section 4.31 would be amended to reflect the nomenclature of §§ 4.40 and 4.41.

Section 4.51 is amended to make clear the applicant's responsibilities with respect to pre-application consultation with Federal, state, and local agencies. The requirements of the documentation process are noted at he beginning of § 4.51, and are removed from other paragraphs of the rules.

Section 16.7 would be revised to refer applicants for a "non-power license" to the requirements of § 4.51 ("major project—existing dam").

Finally, the proposed rule would revoke four existing provisions of the Commission's regulations. The title of Appendix A of Part 2, which prescribes the Environmental Report required of applicants for license under the Act, is revised because the proposed rule contains a new environmental report (Exhibit E). With the adoption of the rule, Appendix A would no longer apply to any type of hydroelectric license. Section 131.2, which prescribes the proper form for an application for license, would be revoked, since the proposed rule contains a new application format. With the adoption of the proposed rule, § 131.2 would no longer apply to any type of hydroelectric license. Similarly, §§ 131.5, which prescribes the form for an application for transmission line only, and § 131.30, which prescribes the form for amendment of license, would be revoked, since the proposed rule contains new application formats for both circumstances. With the adoption of the proposed rule, §§ 131.5 and 131.30 would no longer apply to any type of hydroelectric license.

IV. Written Comment Procedures

The Commission invites interested persons to submit written comments on the matters proposed in this notice. An original and 14 copies of such comments must be filed with the Commission no later than March 27, 1981. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington D.C. 20426. All comments should refer to Docket No. RM80-39.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426. The Commission will consider all

timely comments before acting on the matters proposed in this notice.

(Federal Power Act, as amended, 16 U.S.C. §§ 792–823; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601–2645; DOE Organizational Act, 42 U.S.C. §§ 7101–7352; E.O. 12209, 3 CFR 142 (1978))

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

It is proposed that 18 CFR be amended as follows:

1. Part 4 is amended in the Table of Contents by revising Subparts E and H, and adding a new Subpart L, to read as follows:

PART 4—LICENSES, PERMITS, EXEMPTIONS, AND DETERMINATION OF PROJECT COSTS

. . . . .

Subpart E—Application for License for Major Unconstructed Project and Major Modified Project

Sec.

4.40 Applicability and definitions.
4.41 Contents of application.

. . . . .

Subpart H—Application for License for Transmission Line Only

Sec.

4.70 Applicability and purpose.
4.71 Contents of application.

. . . .

Subpart L—Application for Amendment of License

Sec.

4.200 Applicability and purpose.
4.201 Contents of application.
4.202 Alteration and extension of license.

2. Subpart E (§§ 4.40 and 4.41) is revised to read a follows:

Subpart E—Application for License for Major Unconstructed Project and Major Modified Project

§ 4.40 Applicability and definitions.

(a) *Applicability.* The provisions of §§ 4.40 and 4.41 apply to any application for an initial license for a major unconstructed project that would have a total installed capacity of more than 5 megawatts, and any application for an initial or new license for a major modified project with a total installed capacity more than 5 megawatts. An applicant for license for any major unconstructed or major modified water power project that would have a total installed generating capacity of 5 megawatts or less must submit application under §§ 4.60 and 4.61.

(b) *Definitions.* For the purposes of this subpart:

(1) "Initial license" means any license for a water power project that is issued under the Federal Water Power Act of 1920 or the Federal Power Act.

(2) "Major unconstructed project" means any unlicensed water power project that is proposed to:

(i) have a total installed generating capacity of more than 1.5 MW; and

(ii) use the water power potential of a dam and impoundment which, at the time application is filed, has not been constructed.

(3) "Major modified project" means any major project—existing dam, as defined in § 4.50(b)(5) of this chapter, that is proposed to include:

(i) any repair, modification or reconstruction of an existing dam that would result in a significant change in the normal maximum surface area or the normal maximum surface elevation of an existing impoundment; or surface area or the normal maximum surface elevation of an existing impoundment; or

(ii) any change in existing project works or operations that would result in a significant environmental impact.

(4) "New license" means any license for a water power project that is issued under the Federal Power Act after the initial license for that project, except an annual license issued under section 15 of the Federal Power Act.

(c) *Guidance from Commission staff.* A prospective applicant for a license for a major unconstructed project or major modified project may seek advice from the director of the Commission's Division of Hydropower Licensing

regarding the applicability of those sections to its project [see § 4.31(g)], including the determinations whether any proposed repair, modification or reconstruction of an existing dam would result in a significant change in the normal maximum surface elevation of an existing impoundment, or whether any proposed change in existing project works or operation would result in a significant environmental impact.

(d) *Consultation.* Each application for license for a major unconstructed project or a major modified project must be prepared after consultation with the appropriate Federal, state and local natural resources agencies, which are to be given the opportunity to comment on the proposed project prior to filing of the application. A list of agencies to be consulted may be obtained from the Director of the Commission's Division of Hydropower Licensing. If any agency that an applicant is required to consult fails to provide documentation of the consultation process within a reasonable time, in no case less than 60 days after such documentation is requested, the applicant may submit a summary of the consultation and any recommendations of the agency.

§ 4.41 **Contents of application.**

(a) *Initial statement.*

Before the Federal Energy Regulatory Commission; Application for License for Major Unconstructed Project or Major Modified Project

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for a [license or new license, as appropriate] for the [name of project] water power project, as described in the attached exhibits. [Specify any previous FERC project number designation.]

(2) The location of the project would be:

State or territory: _____
County: _____
Township or nearby town: _____
Stream or other body of water: _____

(3) The exact name, business address, and telephone number of the applicant are:

_____
_____

(4) The applicant is a [citizen of the United States, association of citizens of the United States, domestic corporation, municipality, or state, as appropriate. *See* 16 U.S.C. 796].

(5)(i) The statutory or regulatory requirements of the state(s) in which the project would be located and that affect the project as proposed with respect to bed and banks and to the appropriation, diversion, and use of water for power purposes, and with respect to the right to engage in the business of developing, transmitting, and distributing power and in any other business necessary to accomplish the purposes of the license under the Federal Power Act, are: [provide citation and brief identification of the nature of each requirement]

(ii) The steps which the applicant has taken or plans to take to comply with each of the laws cited above are: [provide brief description for each requirement]

(b) *Exhibit A* is a description of the project. If the project includes more than one dam with associated facilities, each dam and the associated component parts must be described together as a discrete development. The description for each development must contain:

(1) the physical composition, dimensions, and general configuration of any dams, spillways, penstocks, powerhouses, tailraces or other structures proposed to be included as part of the project;

(2) the normal maximum water surface area and normal maximum water surface elevation (mean sea level), gross storage capacity and usuable storage capacity of any impoundments to be included as part of the project;

(3) the number, type and rated capacity of any proposed turbines or generators to be included as part of the project;

(4) the number, length, voltage and interconnections of any primary transmission lines proposed to be included as part of the project [*See* 16 U.S.C. § 796(11)];

(5) the description of any additional mechanical, electrical, and transmission equipment appurtenant to the project; and

(6) all lands of the United States, including lands patented subject to the provisions of section 24 of the Act, 16 U.S.C. § 818, that are enclosed within the project boundary described under paragraph (h) of this section (Exhibit G), identified and tabulated by legal subdivisions of a public land survey, by the best available legal description. The tabulation must show the total acreage of the lands of the United States within the project boundary.

(c) *Exhibit B* is a statement of project operation and resource utilization. If the project includes more than one dam with associated facilities, the information must be provided separately for each discrete development.

The exhibit must contain:

(1) a description of each alternative site considered in arriving at the selection of the proposed site;

(2) a description of alternative facility designs, processes, and operations that were considered;

(3) a statement whether operation of the powerplant will be manual or automatic, an estimate of the annual plant factor, and a statement of how the project will be operated during adverse, mean, and high water years;

(4) an estimate of the dependable capacity and average annual energy production in kilowatt-hours (or mechanical equivalent), and supported by the following data:

(i) the minimum, mean, and maximum recorded flows in cubic feet per second of the stream or other body of water at the powerplant intake or point of diversion, with a specification of any adjustments made for evaporation, leakage minimum flow releases (including duration of releases) or other reductions in available flow; a flow duration curve indicating the period of record and the gauging stations used in deriving the curve; and a specification of the critical streamflow used to determine the dependable capacity;

(ii) an area-capacity curve showing the gross storage capacity and usable storage capacity of the impoundment, with a rule curve showing the proposed operation of the impoundment and how the usable storage capacity is to be utilized;

(iii) the estimated hydraulic capacity of the powerplant in terms of flow and efficiency (cubic feet per second at one-half, full and best gate), and the corresponding generator output in kilowatts;

(iv) a tailwater rating curve; and

(v) a curve showing powerplant capability versus head and specifying maximum, normal, and minimum heads;

(5) a statement of system and regional power needs and the manner in which the power generated at the project is to be utilized, including the amount of power to be used on-site, if any, supported by the following data:

(i) load curves and tabular data as needed;

(ii) details of conservation and rate design programs and their historic and projected impacts on system loads; and

(iii) the amount of power to be sold and the identity of proposed purchaser(s); and

(6) a statement of the applicant's plans for future development of the project or of any other existing or proposed water power project on the affected stream or other body of water, indicating the approximate location and estimated installed capacity of the proposed developments.

(d) *Exhibit C* is a proposed construction schedule for the project. The information required may be supplemented with a bar chart. The construction schedule must contain:

(1) the proposed commencement and completion dates of any new construction, modification, or repair of major project works;

(2) the proposed commencement date of first commercial operation of each new major facility and generating unit; and

(3) if any portion of the proposed project consists of previously

constructed, unlicensed water power structures or facilities, a chronology of original completion dates of those structures or facilities specifying dates (approximate dates must be identified as such) of:

(i) commencement and completion of construction or installation;

(ii) commencement of first commercial operation; and

(iii) any additions or modifications other than routine maintenance.

(e) *Exhibit D* is a statement of costs and financing. The exhibit must contain:

(1) a statement of estimated costs of any new construction, modification, or repair, including:

(i) the cost of any land or water rights necessary to the development;

(ii) the total cost of all major project works;

(iii) indirect construction costs such as costs of construction equipment, camps, and commissaries;

(iv) interest during construction; and

(v) overhead, construction, legal expenses, and contingencies;

(2) if any portion of the proposed project consists of previously constructed, unlicensed water power structures or facilities, a statement of the original cost of those structures or facilities specifying for each, to the extent possible, the actual or approximate costs (approximate costs must be identified as such) of:

(i) any land or water rights necessary to the existing project works; and

(ii) total cost of all major project works; and

(iii) any additions or modifications other than routine maintenance;

(3) if the applicant is a licensee applying for a new license, and is not a municipality or a state, an estimate of the amount which would be payable if the project were to be taken over pursuant to section 14 of the Federal Power Act, 16 U.S.C. § 807, upon expiration of the license in effect including:

(i) fair value;

(ii) net investment; and

(iii) severance damages;

(4) a statement of the estimated average annual cost of the total project as proposed, specifying any projected changes in the costs (life-cycle costs) over the estimated financing or licensing period if the applicant takes such changes into account, including:

(i) cost of capital (equity and debt);

(ii) local, state, and Federal taxes;

(iii) depreciation or amortization, and

(iv) operation and maintenance expenses, including interim replacements, insurance, administrative and general expenses, and contingencies;

(5) a statement of the estimated annual value of project power based on a showing of the contract price for sale of power or the estimated average annual cost of obtaining an equivalent amount of power (capacity and energy) from the lowest cost alternative source, specifying any projected changes in the costs (life-cycle costs) of power from that source over the estimated financing or licensing period if the applicant takes such changes into account;

(6) a statement describing other electric energy alternatives, such as gas, oil, coal and nuclear-fueled powerplants and other conventional and pumped storage hydroelectric plants;

(7) a statement and evaluation of the consequences of the license application being denied and brief perspective of what future use would be made of the proposed site if the proposed project were not constructed, and

(8) a statement specifying the sources and extent of financing and annual revenues available to the applicant to meet the costs identified in paragraphs (e)(1) and (4) of this section.

(f) *Exhibit E* is an Environmental Report. Information provided in the report must be organized and referenced according to the itemized subparagraphs below. If information required is not applicable, applicant must briefly explain why it does not apply. For application for license for a major unconstructed or major modified project submitted under § 4.40–.41, Exhibit E must be prepared in accordance with the consultation provisions in § 4.40(d). For application for license for a major unconstructed or major modified project

with an installed capacity of 5 megawatts or less, Exhibit E must be prepared in accordance with the consultation provisions of § 4.61. The Environmental Report must contain the following information consistent with the scope of the project:

(1) *General Description of the Locale.* The applicant must provide a general description of the environment of the proposed project area and its immediate vicinity. The description must include location and general information helpful to an understanding of the setting.

(2) *Report on Water Use and Quality.* The report must discuss water quality and flows and contain baseline data sufficient to determine the normal and seasonal variability, the impacts expected during construction and operation, and any mitigative, enhancement, and protective measures proposed. The report must be prepared in consultation with the state and federal agencies with responsibility for management of water quality and quantity in the affected stream or other body of water. Consultation must be documented by appending to the report a letter from each agency consulted that indicates the nature, extent, and results of consultation. The report must include:

(i) a description of existing instream flow uses of streams in the project area that would be affected by construction and operation; estimated quantities of water discharged from the proposed project for power production; and any existing and proposed uses of project waters for irrigation, domestic water supply, industrial and other purposes;

(ii) a description of existing water quality in sufficient detail to determine seasonal, vertical, and horizontal variation as appropriate for streams and lakes and reservoirs, including measurements of: significant ions, chlorophyll *a*, nutrients, specific conductance, pH, total dissolved solids, total alkalinity, total hardness, dissolved oxygen, bacteria, temperature, suspended sediments, turbidity and vertical illumination;

(iii) a description of any existing lake or reservoir and any of the proposed project reservoirs including surface area, volume, maximum depth, mean depth, flushing rate, shoreline length, substrate classification, and gradient for streams directly affected by the proposed project;

(iv) a quantification of the anticipated impacts of the proposed construction and operation of project facilities on water quality and downstream flows such as thermal, turbidity and nutrients;

(v) a description of measures recommended by Federal and state agencies and the applicant for the purpose of protecting or improving water quality and stream flows during project construction and operation, and explanation of why the applicant has rejected any measures recommended by an agency; and a description of the application's alternative measures to protect or improve water quality and stream flow;

(vi) a description of groundwater in the vicinity of the proposed project, including water table and artesian conditions, the hydraulic gradient, the degree to which groundwater and surface water are hydraulically connected, aquifers and their use as water supply, and the location of springs, wells, artesian flows and disappearing streams; a description of anticipated impacts on groundwater and measures proposed by the applicant and others for the mitigation of impacts on groundwater; and

(vii) as an appendix, either:

(A) a copy of the water quality certificate (or agency statement that such certification is waived) as described in Section 401 of the Federal Water Pollution Control Air (Clean Water Act) [*see* 33 U.S.C. section 134]; or

(B) a copy of dated letter from the applicant to the appropriate agency requesting such certification.

(3) *Report on Fish, Wildlife, and Botanical Resources.* The applicant must provide a report that describes the fish, wildlife, and botanical resources in the vicinity of the proposed project; expected impacts of the project on these

resources; and mitigation, enhancement, or protection measures proposed. The report must be prepared in consultation with the state agency or agencies with responsibility for these resources, the U.S. Fish and Wildlife Service, the National Marine Fisheries Service (if the proposed project may affect anadromous, estuarine, or marine fish resources), and any state or Federal agency with managerial authority over any part of the proposed project lands. Consultation must be documented by appending to the report a letter from each agency consulted that indicates the nature, extent, and results of the consultation. The report must contain:

(i) a description of existing fish, wildlife, and botanical resources of the proposed project area and its vicinity including any downstream areas affected by the proposed project and the area within the transmission line right-of-way. Information provided must include, but not be limited to, community composition, distribution, density, production, population size and seasonal variation; and any fish, wildlife and botanical species proposed or listed as threatened or endangered by the U.S. Fish and Wildlife Service or National Marine Fisheries Service [*see* 50 CFR §§ 17.11 and 17.12] must be identified;

(ii) a description of the anticipated impacts on fish, wildlife and botanical resources of the proposed construction and operation of project facilities, including predicted changes in size, distribution and production of important populations and the impacts on man's utilization of these resources;

(iii) a description of any measures or facilities recommended by state or Federal agencies and applicant for the mitigation of impacts on fish, wildlife, and botanical resources, or for the protection or enhancement of these resources, including listed archaeological resources in the proposed project area, the impact on threatened or endangered species, and an explanation of why the applicant has determined any measures or facilities recommended by an agency are inappropriate as well as a description of alternative measures proposed by applicant to protect fish, wildlife and botanical resources; and

(iv) the following materials and information regarding the measures and facilities identified under clause (iii) proposed for implementation or construction:

(A) functional design drawings;

(B) a description of proposed operation and maintenance procedures for any measures or facilities;

(C) an implementation, construction and operation schedule for any proposed measures or facilities;

(D) an estimate of the costs of construction, operation, and maintenance of any proposed facilities or implementation of any measures;

(E) a statement of the sources and amount of financing; and

(F) a map or drawing showing, by the use of shading, crosshatching or other symbols, the identity and location of any proposed measures or facilities.

(4) *Report on Historic and Archaeological Resources.* The applicant must provide a report that discusses the historical and archaeological resources in the proposed project area, the impact of the proposed project on those resources and the avoidance, mitigation, and protection measures proposed. The report must be prepared in consultation with the State Historic Preservation Officer (SHPO), the State Archaeologist and the Heritage Conservation and Recreation Service of the U.S. Department of the Interior. Consultation must be documented by appending to the report a letter from each agency that indicates the nature, extent and results of the consultation. The report must contain:

(i) a description of any discovery measures, such as surveys, inventories, and limited subsurface testing work, recommended by the specified state and Federal agencies for the purpose of locating, identifying, and assessing the significance of historic and archaeological resources that would be affected by construction and operation of the proposed project, together with a

statement of the applicant's position regarding the acceptability of the recommendations;

(ii) the results of surveys, inventories, and subsurface testing work recommended by the state and Federal agencies listed above, together with an explanation by the applicant of any variations from the survey, inventory, or testing procedures recommended,

(iii) an identification (without providing specific site or property locations) of any historic or archaeological site in the proposed project area, with particular emphasis on sites or properties either listed in the National Register of Historic Places or recommended as eligible for the National Register by the SHPO that would be affected by the construction of the proposed project;

(iv) a description of the likely direct and indirect impacts of proposed project construction or operation on sites or properties either listed in, or recommended as eligible for, the National Register of Historic Places;

(v) a management plan for the avoidance or mitigation of impacts on historic or archaeological sites and resources based upon the recommendations of the state and Federal agencies listed above and containing the applicant's explanation of variations from those recommendations; and

(vi) the following materials and information regarding the mitigation measures described under clause (v);

(A) a schedule for implementing the mitigation proposals;

(B) an estimate of the cost of the measures; and

(C) a statement of the sources and extent of financing.

(vii) the applicant must provide five copies (rather than the fourteen copies required under § 4.31(b) of the Commission's regulations) of any survey, inventory, or subsurface testing reports containing specific site and property information, and including maps and photographs showing the location and any required alteration of historic and archaeological resources in relation to proposed project facilities.

(5) *Report on Socio-Economic Impacts.* The applicant must provide a report which identifies and quantifies the impacts of constructing and operating the proposed project on employment, population, housing, personal income, local governmental services, local tax revenues and other factors within the towns and counties in the vicinity of the proposed project. The report must include:

(i) identification of the socio-economic impact area;

(ii) a description of employment, population and personal income trends in the impact area;

(iii) an evaluation of any substantial in-migration of people on the impact area's governmental facilities and services, such as police, fire, health and educational facilities and programs;

(iv) on-site manpower requirements and payroll during and subsequent to project construction, including a projection of total on-site employment and construction payroll by month;

(V) numbers of contruction personnel who:

(A) currently reside within the impact area;

(B) would commute daily to the construction site from places situated outside the impact area; and

(C) would relocate on a temporary basis within the impact area;

(vi) a determination of whether the existing supply of available housing within the impact area is sufficient to meet the needs of the additional population;

(vii) numbers and types of residences and business establishments that would be displaced by the proposed project, procedures to be utilized to acquire these properties, and types and amounts of relocation assistance payments that would be paid to the affected property owners and businesses; and

(viii) a fiscal impact analysis which evaluates the incremental local government expenditures against the incremental local government revenues that would result from construction of the proposed project. Incremental expenditures may include, but are not to

be limited to, school operating cost, road maintenance and repair, public safety, and public utility costs.

(6) *Report on Geological and Soil Resources.* The applicant must provide a report on the geological and soil resources in the proposed project area and other lands that would be directly or indirectly affected by the proposed action and the impacts of the proposed project on those resources. The information required may be supplemented with maps showing the location and description of conditions. The report must contain:

(i) a detailed description of geological features, including bedrock lithology, stratigraphy, structural features, glacial features, unconsolidated deposits, and mineral resources;

(ii) a detailed description of the soils, including the types, occurrence, physical and chemical characteristics, erodability and potential for mass movement;

(iii) a description showing the location of existing and potential geological and soil hazards and problems, including earthquakes, faults, seepage, subsidence, solution cavities, active and abandoned mines, erosion, and mass movement, and identification of any large landslides or potentially unstable masses which could be aggravated by reservoir fluctuation;

(iv) a description of the anticipated erosion, mass movement and other impacts on the geological and soil resources due to construction and operation of the proposed project; and

(v) a description of any proposed measures of facilities for the mitigation of impacts on soils.

(7) *Report on Recreational Resources.* The applicant must prepare a report containing a proposed recreation plan describing utilization, design and development of project recreational facilities, and public access. Development of the plan should include consideration of the needs of the physically handicapped. Public and private recreational facilities provided by others that would abut the project should be noted in the report. The report must be prepared in consultation with appropriate local, regional, state and Federal recreation agencies and planning commissions, the Heritage Conservation and Recreation Service of the Department of the Interior, and any other state or Federal agency with managerial authority over any part of the project lands. Consultation must be documented by appending to the report a letter from each agency consulted indicating the nature, extent, and results of the consultation. The report must contain:

(i) a description of any areas within or in the vicinity of the proposed project boundary that are included in, or have been designated for study for inclusion in:

(A) the National Wild and Scenic Rivers Systems (*see* 16 U.S.C. § 1271);

(B) the National Trails System (*see* 16 U.S.C. § 1241); or

(C) a wilderness area under the Wilderness Act (*see* 16 U.S.C. § 1132;

(ii) a detailed description of existing recreational facilities within the project vicinity and the public recreational facilities that are to be provided no later than 3 years from the date of first commercial operation of the proposed project by the applicant at its sole cost or in cooperation with others, and those recreation facilities planned for future development based on anticipated demand. When public recreation facilities are to be provided by other entities, the applicant and those entities should enter into an agreement on the type of facilities to be provided and the method of operation. Copies of agreements with cooperating entities are to be appended to the plan;

(iii) a provision for a shoreline buffer zone within the project boundary above the normal maximum surface elevation of the project reservoir, which buffer zone must be of sufficient width to allow public access to project lands and waters and to protect the scenic, public recreational, cultural, and other environmental values of the reservoir shoreline;

(iv) estimates of existing and future recreational use at the project, in daytime and overnight visitation

(recreation days), with a description of the methodology used in developing these data;

(v) a development schedule and cost estimates of the construction, operation, and maintenance of existing, initial, and future public recreational facilities, including a statement of the source and extent of financing;

(vi) a description of any measures or facilities recommended by the agencies consulted for the purpose of creating, preserving, or enhancing recreational opportunities at the proposed project, and for the purpose of ensuring the safety of the public in its use of project lands and waters, including an explanation of why the applicant has rejected any measures or facilities recommended by an agency; and

(vii) a drawing or drawings, one of which covers the entire project area, clearly delineating:

(A) the location of project lands, and the types and number of existing recreational facilities and those proposed for initial development, including access roads and trails, and facilities for camping, picnicking, swimming, boat docking and launching, fishing and hunting, as well as provisions for sanitation and waste disposal;

(B) the location of project lands, and the type and number of recreational facilities planned for future development;

(C) the location of all project lands reserved for uses other than those included in clauses (A) and (B); and

(D) the project boundary (excluding surveying details) at all areas designated for recreational development, sufficiently referenced to the appropriate Exhibit G drawings to show that all lands reserved for existing and future public recreational development and the shoreline buffer zone are included within the project boundary. Recreational cottages, mobile homes and year-round residences for private use are not to be considered as public recreational facilities, and the lands on which these private facilities are to be developed are not to be included within the proposed project boundary.

(8) *Report on Aesthetic Resources.* The applicant must provide a report that describes the aesthetic resources of the proposed project area, the expected impacts of the project on these resources, and the mitigation, enhancement or protection measures proposed. The report must be prepared following consultation with Federal, state, and local agencies having managerial responsibility for any part of the proposed project lands or lands abutting those lands. Consultation must be documented by appending to the report a letter from each agency consulted that indicates the nature, extent and results of consultation. The report must contain:

(i) a description of the aesthetic character of lands and waters directly and indirectly affected by the proposed project facilities;

(ii) a description of the anticipated impacts on aesthetic resources from construction activity, associated equipment and material, and the subsequent presence of proposed project facilities in the landscape;

(iii) a description of mitigative measures proposed by the applicant, including architectural design, landscaping, and other reasonable treatment to be given project works to preserve and enhance aesthetic and related natural resource values during construction and operation of proposed project facilities; and

(iv) maps, drawings and photographs sufficient to provide an understanding of the information required under this subparagraph. Maps or drawings may be consolidated with other maps or drawings required in this exhibit and must conform to the specifications of § 4.32.

(9) *Report on Land Use.* The applicant must provide a report that describes the existing uses of the proposed project lands and adjacent property, and those land uses that would occur if the project is constructed. The report may reference the discussions of land uses in other

sections of this exhibit. The report must be prepared following consultation with local and state zoning or land management authorities, and any Federal or state agency with managerial authority over proposed project and abutting lands. The report must include:

(i) a description of existing land use in the proposed project area, including identification of wetlands, floodlands, prime or unique farmland as designated by the Soil Conservation Service of the U.S. Department of Agriculture, and lands owned or subject to control by government agencies;

(ii) a description of the proposed land uses within and abutting the project boundary that would occur as a result of development and operation of the project; and

(iii) aerial photographs, maps, drawings or other graphics sufficient to show the location, extent and nature of the land uses referred to in this section.

(10) *Alternatives.* The applicant must provide an environment assessment fo the following:

(i) alternative sites considered in arriving at the selection of the proposed project site;

(ii) alternative facility designs, processes, and operations that were considered and the reasons for their rejection;

(iii) alternative electrical energy sources, such as gas, oil, coal, and nuclear-fueled power plants, purchased power or diversity exchange, and other conventional and pumped-storage hydroelectric plants; and

(iv) the consequences of the license appication being denied.

(11) *List of Literature.* Exhibit E must include a list of all publications, reports, and other literature which were cited or otherwise utilized in the prepartation of any part of the environmental report.

(g) *Exhibit F* consists of general design drawings of the principal project works described under paragraph (b) of this section (Exhibit A) and supporting information used as the basis of design. If the Exhibit F submitted with the application is preliminary in nature, applicant must so state in the application. The drawings must conform to the specifications of § 4.32.

(1) The drawings must show all major project structures in sufficient detail to provide a full understanding of the project, including:

(i) plans (overhead view);

(ii) elevations (front view);

(iii) profiles (side view); and

(iv) sections.

(2) The applicant may submit preliminary design drawings with the application. The final Exhibit F may be submitted at any time during the licensing process and must show the precise plans and specifications for proposed structures. The applicant must submit a final Exhibit F for Commission approval prior to commencement of any construction of the project which occurs after issuance of the license.

(3) *Supporting Design Report.* The applicant must furnish at least the following supporting information to demonstrate that existing and proposed structures are safe and adequate to fulfill their stated functions and must submit such information in a separate report at the time the application is filed. The report must include:

(i) an assessment of the site suitability and reservoir rim stability based on geological and subsurface investigations, including sufficient soils and rock borings and tests for the elevation of all foundations and construction materials to determine the location and type of dam structure suitable for the site;

(ii) copies of boring logs, geology reports and laboratory test reports;

(iii) an identification of all borrow areas and quarry sites and an estimate of required quantities of suitable material;

(iv) stability and stress analyses for all major structures and critical abutment slopes under all probable loading conditions, including seismic and hydrostatic forces induced by water loads up to the Probable Maximum Flood as appropriate; and

(v) the bases for determination of seismic loading and the Spillway Design

Flood in sufficient detail to enable independent evaluation.

(4) The applicant must submit five copies of the supporting design report described in subparagraph (3) above (not fourteen copies as required under § 4.31(b) of the Commission's regulations) at the time preliminary and final design drawings are submitted to the Commission for review.

(h) *Exhibit G* is a map of the project that must conform to the specifications of § 4.32. If more than one sheet is used, the sheets must be numbered consecutively, and each sheet must bear a small insert sketch showing the entire project and indicating that portion depicted on the sheet. If at any time after the application is filed there is any change in the project boundary, the applicant must submit, within a reasonable period following the completion of project construction, a final Exhibit G showing the extent of such changes.

The map must show:

(1) *Location of the project and principal features.* The map must show the location of the project as a whole with reference to the affected stream or other body of water and, if possible, to a nearby town or any other permanent monuments or objects, such as roads, transmission lines or other structures, that can be noted on the map and recognized in the field. The map must also show the relative locations and physical interrelationships of the principal project works and other features described under paragraph (b) of this section (Exhibit A).

(2) *Project boundary.* The map must show a project boundary enclosing all of the principal project works and other features described under paragraph (b) of this section (Exhibit A). If accurate survey information is not available at the time the license application is filed, applicant must so state and a tentative boundary may be submitted. The boundary must enclose only those lands necessary for operation and maintenance of the project and for other project purposes, such as flowage, public recreation, shoreline control or protection of environmental resources. If the boundary is on land coverd by a public land survey, ties must be shown on the map at sufficient points to permit accurate platting of the position of the boundary relative to the lines of the public land survey. If the lands are not covered by a public land survey the best available legal description of the position of the boundary must be provided, including distances and directions from fixed monuments or physical features. The boundary must be described as follows:

(i) *Impoundments.* The boundary around a project impoundment must be located no more than 200 feet (horizontal measurement) from the exterior margin of the reservoir, defined by the normal maximum surface elevation, except where deviations may be necessary in describing the boundary according to the method used, or where additional lands are necessary for project purposes, such as public recreation. The boundary may be described by any combination of the following methods:

(A) contour lines, including the contour elevation [preferred method];

(B) specified courses and distances (metes and bounds); or

(C) if the project lands are covered by a public land survey, lines parallel to the lines of the survey.

(ii) *Continuous features.* The boundary around linear project features such as access roads, transmission lines and conduits may be described by specified distances from center lines or offset lines of survey. The width of such corridors must not exceed 200 feet, unless good cause is shown for a greater width. Several sections of a continuous feature may be shown on a single sheet, with information showing the sequence of continuous sections.

(iii) *Noncontinuous features.* The boundary around noncontinuous project works such as dams, spillways and powerhouses must enclose only those lands that are necessary for safe and efficient operation and maintenance of the project, or for other specified project

purposes, such as public recreation or protection of environmental resources. The boundary may be described by any combination of the following methods:

(A) contour lines;

(B) specified courses and distances; or

(C) if the project lands are covered by a public land survey, lines upon or parallel to the lines of the survey.

(3) *Federal Lands.* Any public lands and reservations of the United States ("Federal lands") [*see* 16 U.S.C. § 796(1) and (2)] that are within the project boundary, such as lands administered by the U.S. Forest Service, Bureau of Land Management, or National Park Service, or Indian tribal lands, and the boundaries of those Federal lands, must be identified on the map by:

(i) legal subdivisions of a public land survey of the affected area (a protraction of identified township and section lines is sufficient for this purpose); and

(ii) the Federal agency, identified by symbol or legend, that maintains or manages each identified subdivision of the public land survey within the project boundary; or

(iii) in the absence of a public land survey, the location of the Federal lands according to the distances and directions from fixed monuments or physical features. When a Federal survey monument or a Federal bench mark will be destroyed or rendered unusable by the construction of project works, at least two permanent, marked witness monuments or bench marks must be established at accessible points. The maps show the location (and elevation, for bench marks) of the survey monument or bench mark which will be destroyed or rendered unusable, as well as of the witness monuments or bench marks. Connecting courses and distances from the witness monuments or bench marks to the original must also be shown.

(4) *Non-Federal Lands.* For those lands within the project boundary not identified under paragraph (h)(3) of this section, the map must identify by legal subdivision:

(i) lands owned in fee by the applicant and lands that the applicant plans to acquire in fee; and

(ii) lands over which the applicant has acquired or plans to acquire rights to occupancy and use other than fee title, including rights acquired to be required by easement or lease.

3. Section 4.31 is amended by revising paragraph (a)(2)(iii) to read as follows:

§ 4.31 Acceptance for filing or rejection.

(a) * * *

(2) * * *

(iii) License for a major unconstructed project and a major modified project: §§ 4.40 and 4.41;

* * * * *

4. Section 4.50 is amended by revising paragraph (a) to read as follows:

§ 4.50 Applicability and definitions.

(a) *Applicability.* (1) The provisions of §§ 4.50 and 4.51 apply to any application for either an initial license or new license for a major project—existing dam that would have a total installed capacity of more than 5 megawatts, except any such project [*see* § 4.40] that would:

(i) include any proposed repair, modification or reconstruction of an existing dam that would result in a significant change in the normal maximum surface area or normal maximum surface elevation of an existing impoundment; or

(ii) include any proposed new development or change in project operation that would result in a significant environmental impact.

(2) An applicant for license for any major project—existing dam that would have a total installed capacity of more than 5 megawatts or less must submit application under §§ 4.60 and 4.61.

* * * * *

5. Section 4.50 is amended in paragraph (b)(5) by adding the work "and" at the end of clause (i), by removing the semicolon at the end of clause (ii), and inserting a period in lieu thereof, and by revoking and removing clauses (iii) and (iv).

6. Section 4.51 is amended by revising the introductory statement and the introductory statement of paragraph (f) to read as follows:

§ 4.51 Contents of application.

Each application for a license for a major project—existing dam must be prepared after consultation with the appropriate Federal, state, and local resources agencies, which are to be given the opportunity to comment on the proposed project prior to filing of the application. A list of agencies to be consulted may be obtained from the Director of the Commission's Division of Hydropower Licensing. If any agency that an applicant is required to consult fails to provide documentation of the consultation process within a reasonable time, in no case less than 60 days after such documentation is requested, the applicant may submit a summary of the consultation and any recommendations of the agency.

* * * * *

(f) *Exhibit E* is an environmental report. Information provided in the report must be organized and referenced according to the provisions of this paragraph. If a request for information is not applicable, the applicant must briefly explain why it does not apply. The environmental report must contain the following elements:

* * * * *

7. Subpart H (§§ 4.70 and 4.71) is revised to read as follows:

§ 4.70 Applicability and purpose.

This subpart applies to any application or license issued solely for a transmission line that transmits power from a licensed water power project or other hydroelectric project authorized by Congress to the point of junction with the distribution system or with the interconnected primary transmission system.

§ 4.71 Contents of application.

Each application for license for transmission line only must be prepared after consultation with appropriate Federal, state, and local resources agencies which are to be given the opportunity to comment on the proposed project prior to filing of the application. A list of the agencies to be consulted can be obtained from the Director of the Commission's Division of Hydropower licensing. If any agency that an application is required to consult fails to provide documentation of the consultation process within a reasonable time, in now case less than 30 days after documentation is requested, the applicant may submit a summary of the consultation and any recommendations of the agency.

(a) *Initial statement.*

Before the Federal Energy Regulatory Commission.

Application for License for Transmission Line Only

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for a [license or new license, as appropriate] for the [name of project] transmission line only, as described in the attached exhibits, that is connected with FERC Project No. ———, for which a license [was issued, or application was made, as appropriate] on the —— day of ————————, 19—.

(2) The location of the transmission line would be:

State or territory: ————————
County: ————————
Township or nearby town: ————————

(3) The proposed use or market for the power to be transmitted.

(4) The exact name, business address, and telephone number of the applicant are:

————————
————————
————————

(5) The applicant is a [citizen of the United States, association of citizens of the United States, domestic corporation, municipality, or state, as appropriate, *see* 16 U.S.C. § 796].

(b) *Required exhibits.* The application must contain the following exhibits, as appropriate:

(1) For any transmission line that, at the time the application is filed, is not constructed and is proposed to be

connected to a licensed water power project with an installed generating capacity of more than 5 MW—Exhibits A, B, C, D, E, F, and G under § 4.41 of this chapter;

(2) For any transmission line that, at the time the application is filed, is not constructed and is proposed to be connected to a licensed water power project with an installed generating capacity of 5 MW or less—Exhibits E, F, and G under § 4.61 of this chapter; and

(3) For any transmission line that, at the time the application is filed, has been constructed and is proposed to be connected to any licensed water power project—Exhibits E, F, and G under § 4.61 of this chapter.

8. Part 4 is amended by adding a new Subpart L to read as follows:

Supart L—Application for Amendment of License

§ 4.200 Applicability and purpose.

This part applies to any application for amendment of a license where the applicant desires to:

(a) make a change in the physical features of the project or its boundary, or make an addition, betterment, abandonment, or conversion, of such character as to constitute an alteration of the license;

(b) make a change in the plans for the project under license; or

(c) extend the time fixed on the license for commencement or completion of project works.

§ 4.201 Contents of application.

Each application for amendment of a license for a water power project must be prepared after consultation with appropriate Federal, state, and local resources agencies, which are to be given the opportunity to comment on the proposed amendment prior to filing of the application. A list of the agencies to be consulted can be obtained from the Director of the Commission's Division of Hydropower licensing. If any agency that an applicant is required to consult fails to provide documentation of the consultation process within a reasonable time, in no case less than 30 days after such documentation is requested, the applicant may submit a summary of the consultation and any recommendations of the agency.

(a) *Initial statement.*

Before the Federal Energy Regulatory Commission

Application for Amendment of License

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for an amendment of license for the [name of project] water power project.

(2) The exact name, business address, and telephone number of the applicant are:

_____

_____

_____

(3) The applicant is a [citizen of the United States, association of citizens of the United States, domestic corporation, municipality, or state, as appropriate, see 16 U.S.C. § 796], licensee for the water power project, designated as Project No. ——— in the records of the Federal Energy Regulatory Commission, issued on the —— day of ————, 19—.

(4) Give a statement or description of the changes desired and the reason(s) the proposed changes are necessary.

(b) *Required exhibits.* The application must contain the following exhibits, as appropriate:

(1) For amendment of a license for a water power project that, at the time the application is filed, is not constructed and is proposed to have an installed generating capacity of more than 5 MW—Exhibits A, B, C, D, E, F, and G under § 4.41 of this chapter;

(2) For amendment of a license for a water power project that, at the time the application is filed, is not constructed and is proposed to have an installed generating capacity of 1.5 MW or less—Exhibits E, F, and G under § 4.61 of this chapter;

(3) For amendment of a license for a water power project that, at the time the application is filed, is not constructed and is proposed to have an installed generating capacity of more than 1.5 MW, but less than 5 MW—Exhibits F

and G under § 4.61 of this chapter, and Exhibit E under § 4.41 of this chapter;

(4) For amendment of a license for a water power project that, at the time the application is filed, has been constructed and has, or is proposed to have, an installed generating capacity of more than 5 MW—Exhibits A, B, C, D, E, F, and G under § 4.61 of this chapter.

(c) *Consultation and waiver.* If an applicant for license under this subpart believes that any exhibit required under paragraph (b) of this section is inappropriate with respect to the particular amendment of license sought by the applicant, a petition for waiver of the requirement to submit such exhibit may be submitted under § 1.7 of this chapter, after consultation with the Commission's Division by Hydropower Licensing.

§ 4.202 Alteration and extension of license.

(a) If it is determined that approval of the application for amendment of license would constitute a significant alteration of license pursuant to section 6 of the Act, ,6 U.S.C. § 799, public notice of such application shall be given at least 30 days prior to action upon the application.

(b) Any application for extention of time fixed in the license for commencement or completion of construction of project works must be filed with the Commission not less than three months prior to the date or dates so fixed.

PART 5 [Removed]

9. Part 5 is revoked and removed.

10. Section 16.7 is amended by revising the introductory statement to read as follows:

§ 16.7 Application for non-power license.

Each application for a "non-power license" must conform to the requirements of § 4.51 of this chapter and must include the information specified in paragraphs (a) through (c) of this section. The application and all accompanying exhibits must be filed in accordance with § 4.31 of this chapter.

* * * * *

§ 131.2 [Removed]

11. Section 131.2 is revoked and removed.

§ 131.5 [Removed]

12. Section 131.5 is revoked and removed.

PART 2—APPENDIX [AMENDED]

13. Part 2 is amended by revising the title of Appendix A to read:

Appendix A

Guidelines for the Preparation of Environmental Reports for Applications under sections 202(b), 210, 211, and 212 of the Federal Power Act, as specified in § 380.12(b).

* * * * *

¶ 32,109 Ceiling Prices; High-Cost Gas Produced From Tight Formations (Colorado-11)

46 F. R. 11839 (February 11, 1981).

18 CFR Part 271

[RM 79-76 (Colorado-11)]

Ceiling Prices; High Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado Oil and Gas Conservation Commission that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on March 6, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on February 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

I. Background

On January 23, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Mancos "B" Formation located in Rio Blanco and Garfield Counties, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Mancos "B" Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located approximately 30 to 70 miles south of Rangely, Colorado, and approximately 50 to 70 miles northwest of Grand Junction, Colorado, in the Douglas Creek Arch area. The west side of the recommended area parallels the highway from Grand Junction to Rangely, Colorado. Total acreage is approximately 264,538 with 15.3 percent being fee and 84.7 percent federal acreage. The Mancos "B" is a member of the Mancos Shale Formation, occurring in the middle third of the sequence. It consists of thinly bedded and interlaminated, very fine-grained sandstone, siltstone, and shale and ranges from 400 to 700 feet in thickness. The depth to the top of the Mancos "B" Formation averages 3603 feet.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Colorado Cause No. NG–15 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Mancos "B" Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North North Capitol Street, N.E., Washington, D.C. 20426, on or before March 6, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–11), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than February 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (32) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(17) through (31) [Reserve]

(32) *Mancos "B" Formation in Colorado.* (i) *Delineation of formation.* The Mancos "B" Formation is found in the Douglas Creek Arch area in Rio Blanco and Garfield Counties, Colorado. RM79-76 (Colorado-11)

(ii) *Depth.* The Mancos "B" Formation is a member of the Mancos Shale of upper Cretaceous age, occurring in the approximate middle third of the Mancos sequence. The average depth to the top of the Mancos "B" Formation is 3603 feet.

¶ 32,110 High-Cost Gas Produced From Tight Formations (Colorado-13)

46 F. R. 11840 (February 11, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-13)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced for tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado Oil and Gas Conservation Commission that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on March 6, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on February 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

United States of America Federal Energy Regulatory Commission

High-Cost Gas Produced from Tight Formations; Docket No. RM79-76 (Colorado-13); Notice of Proposed Rulemaking by Director, OPPR.

(Issued February 4, 1981).

I. Background

On January 26, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Mancos "B" Formation located in Rio Blanco County, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Mancos "B" Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located in Rio Blanco County, Colorado, approximately 70 miles northwest of Grand Junction, Colorado, on the northeast flank of the Douglas Creek Arch in the Piceance Basin. The area comprises 151,680 acres, of which 96.4 percent is Federal acreage, 3.5 percent is fee, and 0.1 percent is state. The Mancos "B" Formation is a member of the Mancos Shale Formation and usually occurs in the upper third of the sequence. It consists of thinly bedded

and interlaminated, very fine-grained sandstone, siltstone, and shale and ranges from 400 to 700 feet in thickness. The recommended formation dips to the northeast at a rate of 500 to 600 feet per mile. The depth to the top of the formation ranges from 1500 to 8400 feet and averages 3500 feet.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Colorado Cause No. NG–14 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more that five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Mancos "B" Formation, as described and delineated in Colorado's recommendation on file with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before March 6, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–13), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than February 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342.)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,
Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (35) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent

and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(17) through (34) [Reserved]

(35) *Mancos "B" Formation in Colorado.* RM79-76 (Colorado—13)

(i) *Delineation of formation.* The Mancos "B" Formation is located in Rio Blanco County, Colorado, approximately 70 miles northwest of Grand Junction, Colorado, on the northeast flank of the Douglas Creek Arch in the Piceance Creek Basin.

(ii) *Depth.* The Mancos "B" Formation is a member of the Mancos Shale and occurs in the upper third of the Mancos sequence. The thickness of the Mancos "B" formation ranges from 400 to 700 feet. The depth to the top of the formation ranges from 1500 feet to 8400 feet and averages 3500 feet.

¶ 32,111 High-Cost Gas Produced From Tight Formations (Colorado-10)

46 F. R. 11841 (February 11, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-10)]

High-Cost Gas Produced from Tight Formations, Colorado

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price. (18 CFR 271.703). The rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This Notice of Proposed Rulemaking by the Director of the Office of Pipeline and Producer Regulation contains a recommendation of the Colorado Oil and Gas Conservation Commission that the Morrow Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on March 6, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on February 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

Issued February 4, 1981.

High-Cost Gas Produced from Tight Formations; Docket No. RM79-76 (Colorado-10); Notice of Proposed Rulemaking by Director, Oppr.

I. Background

On January 26, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Morrow Formation located in Kiowa County, Colorado be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Morrow Formation be designated a tight formation should be adopted. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation lies within Kiowa County, Colorado, on the southwest flank of the Las Animas Arch, approximately 24 miles north of the town of Lamar in southeastern Colorado. The recommended area comprises all of Township 18 South, Range 45 West, and contains approximately 231,040 acres, of which 6% is state land and 94% is fee. The average depth to the producing interval is 4500 feet. The Morrow Formation which averages 185 feet in thickness, is basically blanket shale formation in which lenticular sands of various composition and physical characteristics occur. These sandstones

vary from 5 to 12 feet in thickness and are the source of gas production.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–16 convened by Colorado on this matter demonstrates that:

(1) The recommended formation exhibits low permeability characteristics, and the price established in § 271.703(a) is necessary to provide reasonable incentives for production of gas from the recommended formation.

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production form the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that typical casing design of wells drilled into the area protects any fresh water aquifers, as required by the rules and regulations of the Colorado Oil and Gas Conservation Commission.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Morrow Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public comment procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before March 6, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado—10), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than February 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new paragraph (31) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket

No. RM79–76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(18) through (30) [Reserved]

(31) *The Morrow Formation in Colorado.* RM79–76 (Colorado—10).

(i) *Delineation of formation.* The Morrow Formation is found in Kiowa County, Colorado. It is located north of the town of Lamar in southeastern Colorado, and underlies all of Township 18 South, Range 45 West, 6th p.m.

(ii) *Depth.* The Morrow Formation is defined as that formation occurring at an average measured depth of 4500 feet.

¶ 32,112 High-Cost Gas Produced From Tight Formations (Colorado-12)

46 F. R. 11842 (February 11, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado—12)]

High-Cost Gas Produced from Tight Formations; Colorado

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas a high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit the the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado Oil and Gas Conservation Commission that the Cozzette and Corcoran Formations each be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on March 6, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on February 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

Issued: February 4, 1981.

High-cost gas produced from tight formations; Docket No. RM79-76 (Colorado—12); Notice of Proposed Rulemaking by director, OPPR.

Background

On January 26, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Cozzette and Corcoran Formations, located in Garfield County, Colorado, each be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Cozzette and Corcoran Formations each be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formations underlie a portion of Garfield County, Colorado. The area comprises approximately 50,886 acres, of which 84.2 percent is federal land and 15.8 percent is fee. The formations are located in the Piceance Creek Basin, approximately 12 miles southwest of the town of Glenwood Springs, Colorado. The Cozzette and Corcoran Sandstones are considered to be members of the lower Mesaverde Formation of Cretaceous age. The average depth to the top of the Cozzette Formation is 7477

feet, and it averages approximately 200 feet in thickness. The average depth to the top of the Corcoran Formation is 7677 feet, and it averages approximately 200 feet in thickness. The base of the Corcoran Formation is defined as the top of the Mancos Shale Formation.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Colorado Cause No. NG–17, convened by Colorado on this matter, demonstrates that:

(1) The average *in situ* gas permeability throughout the pay sections of the proposed areas is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formations, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formations is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of these formations will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Cozzette and Corcoran Formations, as described and delineated in Colorado's recommendation as filed with the Commission, each be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before March 6, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RN79–76 (Colorado—12), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time request at the hearing. Requests should be filed with the Secretary of the Commission no later than February 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams

Director, Office of Pipeline and Producer Regulations.

Section 271.703(d) is amended by adding new subparagraphs (33) and (34) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent

and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdicational agency that submitted the recommendation.

• • • • •

(18) through (32) [Reserved]

(33) *Cozzette Formation in Colorado.* RM79–76 (Colorado—12)

(i) *Delineation of formation.* The Cozzette Formation is located in the Piceance Creek Basin in Garfield County, Colorado, approximately 12 miles southwest of the town of Glenwood Springs, Colorado.

(ii) *Depth.* The Cozzette Formation is a member of the lower Mesaverde Group. The average depth to the top of the Cozzette Formation is 7477 feet. Its base is defined as the top of the Corcoran Formation.

(34) *Corcoran Formation in Colorado* RM79–76 (Colorado—12)

(i) *Delineation of Formation.* The Corcoran Formation is located in the Piceance Creek Basin in Garfield County, Colorado, approximately 12 miles southwest of the town of Glenwood Springs, Colorado.

(ii) *Depth.* The Corcoran Formation is a member of the lower Mesaverde Group. The average depth to the top of the Corcoran Formation is 7677 feet. Its base is defined as the top of the Mancos Shale Formation.

¶ 32,113 High-Cost Gas Produced From Tight Formations (Louisiana-3)

46 F. R. 12760 (February 18, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Louisiana-3)]

High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the State of Louisiana Office of Conservation that the Cotton Valley Formation be designated as a tight formation under § 271.703(d).

DATES: Comments on the proposed rule are due on March 13, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on February 26, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Ting Chin, (202) 357-8769/John Bassett (202) 357-8657.

Issued: February 11, 1981.

I. Background

On January 15, 1981, the State of Louisiana Office of Conservation (Louisiana) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Cotton Valley Formation, located in the northwest part of the state of Louisiana, be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Louisiana's recommendation that the Cotton Valley Formation be designated a tight formation should be adopted. Louisiana's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The Cotton Valley Formation, underlying specified portions of the Elm Grove Field in Caddo and Bossier Parishes, North Louisiana, is basically a marine formation characterized by alternating sands and shales. (A more detailed description of the recommended area is contained in the recommendation on file with the Commission.) It is defined as that formation occurring between the measured depths of 8590 feet and 9360 feet on the induction electrical log of the Northeast Resources Inc.—Frierson No. 1 Well.

III. Discussion of the Recommendation

Louisiana claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Louisiana on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Louisiana further asserts that the requirements of Statewide Order No. 29–B will assure that development of the Cotton Valley Formation will not adversely affect any fresh water aquifer that is or is expected to be used as a domestic or agricultural water supply. In addition, Louisiana states that it is in the process of establishing rules and regulations in accordance with the Environmental Protection Agency's Underground Injection Control guidelines which it believes will further prevent the contamination of any fresh water aquifer.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commision Order No. 97, issued August 1, 1980 in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Louisiana that the Cotton Valley Formation, as described and delineated in Louisiana's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before March 13, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Louisiana-3), and should give reasons, including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than February 26, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432.)

According, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Louisiana's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (30) to read as follows:

§ 271.703 Tight Formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, as subindexed below, and is also located in the officials files of the jursidictional agency that submitted the recommendation.

* * * * * *

(17) through (29) [Reserved]

(30) *Cotton Valley Formation in Louisiana.* RM79–76 (Louisiana-3).

(i) *Delineation of formation.* The Cotton Valley Formation, basically a marine formation with alternating sands and shales, is located in Caddo and Bossier Parishes, North Louisiana.

(ii) *Depth.* The Cotton Valley Formation is defined as that formation occuring between the measured depths of 8,590 feet and 9,360 feet on the induction electrical log of the Northeast Resources Inc.—Frierson No. 1 Well located in Section 21, Township 16 North, Range 12 West, Caddo Parish.

¶ 32,114 Applications for Preliminary Permit and License for Water Power Projects

46 F. R. 14751 (March 2, 1981).

18 CFR Parts 1 and 4

[Docket No. RM81-15]

Revisions to Certain Regulations Governing Applications for Preliminary Permit and License for Water Power Projects

Issued February 21, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to amend certain provisions in its regulations governing preliminary permit and license applications for water power projects. The proposed revisions are designed to aid the expeditious development of water power projects by eliminating unnecessary procedures, requiring certain necessary information in applications, and correcting the standard for evaluating certain competing applications. The rule would affect existing §§ 1.8, 4.31, 4.33, 4.51, and 4.81 and create a new § 4.35.

DATES: Written comments by April 6, 1981.

ADDRESS: File comments with: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:
Ronald Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, Federal Energy Regulatory Commission, Washington, D.C. 20426 (202) 376-9171;
James Hoecker, Office of the General Counsel, Federal Energy Regulatory Commission, Washington, D.C. 20426 (202) 357-9342.

SUPPLEMENTARY INFORMATION:

The Federal Energy Regulatory Commission (Commission) proposes to amend certain provisions in its regulations governing preliminary permit and license applications for water power projects. The proposed revisions are designed to aid the expeditious development of water power projects by eliminating unnecessary procedures, requiring certain necessary information in applications, and correcting the standard for evaluating certain competing applications. The rule would affect existing §§ 4.33, 4.51, and 4.81 and create a new § 4.35.

I. Background

Over the past two years, the Commission has carried forward a program of licensing reform for water power projects, including revision of the regulations governing preliminary permit applications and various kinds of license applications.[1] The revised

[1] Order No. 54 "Regulations Prescribing General Provisions for Preliminary Permit and License Applications; and Regulations Governing applications for Amendments to and Cancellation of Preliminary Permits" (Docket No. RM79-23), issued October 22, 1979, 44 Fed. Reg. 61328, October 25, 1979.

Order No. 59, "Regulations Governing Applications for License for, Major Projects—Existing Dam "(Docket No. RM79-36) issued December 16, 1979, 45 Fed Reg. 75383, December 28, 1979.

Notice of Proposed Rulemaking, "Regulations Governing Applications for Minor Water Power Projects and Major Water Power Projects 5 Megawatts or Less" (Docket No. RM81-10), issued January 21, 1981, 46 Fed. Reg. 9837, January 29, 1981.

Notice of Proposed Rulemaking, "Regulations Governing Application for License for Major Unconstructed and Major Modified Projects; Applications for License for Transmission Line Only; Applications for Amendment to License (Docket No. RM80-39), issued January 23, 1981, 46 Fed Reg. 10165, February 2, 1981.

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regulations have helped to reduce the time an applicant must devote to preparing an application and have enabled the Commission to process applications more quickly than before. For example, it now takes 3 to 4 months to process an application for preliminary permit, instead of the customary 18 months previously.

Despite this progress, the renewed interest in hydropower development—inspired in part by the Commission's small power production and cogeneration rulemakings [2] and its current program to exempt from all or part of Part I of the Federal Power Act [3]—has increased the Commission's workload dramatically. For example, the Commission received 18 preliminary permit applications in 1977, 36 in 1978, 76 in 1979. However, in 1980 the Commission received 501 such applications and the rate of submittal in 1981 is thus far even greater.

This rulemaking is designed to expedite further the licensing of water power projects by clarifying and streamlining some Commission procedures that have previously caused regulatory problems.

1. Intervention in proceedings initiated by the filing of a preliminary permit application are proposed to be granted automatically, with some exceptions, both because the multiple interventions in such proceedings are largely to obtain service of papers and to protect the potential interests of certain parties, including state commissions, and because the permits themselves normally do not entail substantial environmental consequences that would be a basis for genuine opposition to the project. This would obviate issuance of routine orders to grant intervention.

2. The filing of a notice of intent to file a competing preliminary permit application has frequently and unnecessarily extended (2 to 3 months) the notice period required for applications and thereby delayed the opportunity for Commission action. The owner of a potential site for which a non-owner has filed a permit application is sufficiently shielded from surprise because notice of the application will always be mailed by the Commission directly to that person.

3. Under section 3(7) of the Federal Power Act, a "municipality" must be "competent under the laws [of the state] thereof to carry on the business of developing transmitting, utilizing, or distributing power." This qualification is particularly important for administration of the state/municipal preference under section 7(a) of the Act. Without evidence of this competency in the permit or license application, the Commission must research state laws if it does not want to risk affording a preference to the inappropriate person.

4. Applications for a preliminary permit or a license are occasionally altered in a manner that changes the status of the filing party (*e.g.*, from "citizen" to "municipality") or the fundamental plan of development. For purposes of establishing a priority of filing, fairness dictates that such changes be regarded as the filing of a new application.

5. Finally, section 7(a) of the Act requires that, where at least one competing preliminary permit or license applicant is a state or municipality and another is not, public entities are preferred to non-public applicants if the plans of each are "equally well adapted to conserve and utilize in the public interest the water resouces of the region." The ability of the parties to

[2] Order No. 69, "Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978" (Docket No. RM79-55), issued February 19, 1980, 45 FR 12214, February 25, 1980; Order No. 70, "Small Power Production and Cogeneration Facilities—Qualifying Status" (Docket No. RM79-54), issued March 13, 1980, 45 FR 17959, March 20, 1980.

[3] Order No. 106, "Exemption from all or part of Part I of the Federal Power Act of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less" (Docket No. RM80-85), issued November 7, 1980, 45 FR 78115, November 18, 1980.

carry out the plans is not a proper test to apply to such applications unless none of the competing applicants is a public entity.

II. Summary of the proposed rule.

1. *Interventions. Sections 1.8(f)(2) and 4.31(h).* The proposed rule would automatically grant a person who files under § 1.8 a timely petition to intervene in a preliminary permit proceeding the status of party to that proceeding, unless and until the Commission or other decisional authority denies or stays such a petition or unless that petition is opposed by the preliminary permit applicant or other party under § 1.8(e). [4]

2. *Notices of intent. Section 4.33(a).* The Commission will not accept notices of intent to submit competing preliminary permit applications for specified kinds of projects. Any prospective competitor may only file with the Commission a competing permit application within the time specified in the public notice and must, therefore, decide sooner to compete for the hydropower site.

3. *Evaluating competing applications. Sections 4.33(g)(3) and (4).* To conform with section 7(a) of the Federal Power Act, the test to be applied to competing applications for permit or license, where one applicant is a public entity and another is not, is revised by deleting reference to the ability of the respective applicants to carry out the proposed plans of development. The appropriate tests relate to the relative merits of the plans, which may include factors of economic feasibility, and to the nature of the applicants.

4. *Evidence of competence under section (3)(7) of the Act. Sections 4.33(i), 4.51(a)(4), 4.81(a)(4).* A municipal applicant for preliminary permit for any project or for license for a major project—existing dam must supply evidence that it is competent under state law to be in the power business. If it fails to do so, it will be treated as a non-public applicant under § 4.33. The Commission also proposes to include similar provisions in the revised regulations for minor, major unconstructed, and major modified water power projects, at the time those regulations are issued in final orders. [5]

5. *Change of filing dates as a result of material amendment. Section 4.35.* The rule creates a new section to indicate that any material change in an application after it is filed with the Commission, such as by changing the nature of the applicant (*e.g.* from citizen to municipality) or by making significant fundamental changes in the plan of development, will result in a revision of the date of acceptance for filing. This could change an applicant's priority status relative to competing applicants under § 4.33.

III. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) requires certain analyses of proposed agency rules that will have a "significant economic impact on a substantial number of small entities."

Pursuant to section 605(a) of the RFA, the Commission hereby finds that the analysis requirements set forth in the rulemaking do not apply to this rulemaking, for the following reasons:

The primary purpose of this proposal is to clarify, simplify, and streamline application procedures for the preliminary permit and license for hydroelectric power projects. To this end, for example, this proposal would grant automatic intervention in certain instances—thereby obviating the need for unnecessary, individualized orders to grant intervention and would also avoid delays occasioned by the filing of

[4] Section 1.17(c) currently affords service to any petitioner for intervention. The Commission will be considering proposed revised Rules of Practice and Procedure (Docket No. RM78-22) in which persons requesting intervention would be granted automatic intervention, included on the relevent service lists, and permitted the right to make motions, unless the petition is denied by order of the Commission.

[5] *See* Notices of Proposed Rulemaking in Footnote 1, *supra.*

notices of intent to submit competing preliminary permit applications for certain projects. Concededly, this latter proposal will require would-be project sponsors (including small private developers and small municipalities) to reach a decision quickly about filing a competing application; this may create some minimal additional burdens for small private and public developers, but these slight burdens should be more than offset by the advantages small developers will realize by virtue of a shorter, less costly application process, and a more rapid Commission decision. Accordingly, on balance, there seems to be no significant impact.

Similarly, some slight additional filing burden may be imposed by the proposed view requirement that evidence of competency under state law be submitted by municipal applicants; but again, that minimal burden should be offset by the elimination of any delays that might otherwise result if the Commission had to independently verify the applicant's authority and status under state law. Accordingly, the net economic impact of this change should not be significant.

The proposal to delete any reference to the ability of competing public and non-public applicants to carry out their proposals, is simply intended to conform the Commission's rules to the plain mandate of section 7(a) of the Federal Power Act. In any event, the elimination of this standard should not impose significant economic impacts on any ascertainable class of small entities.

Finally, the proposed change of filing dates in the event of material amendments to a permit or license application, may in a particular case alter priorities previously established by the filing of the original applications; and that alteration may work a significantly beneficial or adverse impact upon some particular applicants. By itself, however, this proposal will not create any direct, ascertainable, general impact upon a substantial number of small entities.

Hence, in view of the minimal effects of these changes, and their procedural nature, the Commission believes its certification of no significant economic impact is entirely proper.

IV. Comment Procedure

The Commission invites interested person to submit written comments on the matters proposed in this notice. An original and 14 copies of such comments must be filed with the Commission not later than April 6, 1981. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. All comments should refer to Docket No. RM81–15.

Written comments will be placed in the Commission's public files and wil be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426. The Commission will consider all timely comments before acting on the matters proposed in this notice.

(Federal Power Act, as amended, 16 U.S.C. §§ 782–828c; the Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 3 CFR, 1977 Comp., p. 142)

By direction of the Commision.

Kenneth F. Plumb,

Secretary.

1. Section 1.8 is amended in paragraph (f) by adding a new subparagraph (3) to read:

§ 1.8 Interventions.

* * * * *

(f) *Notice and action on petitions—*

* * * * *

(3) *Preliminary permit proceedings.* For any petition to intervene filed pursuant to an application for preliminary permit for a water power project, the Commission will grant limited automatic intervention under § 4.31(h) of this chapter.

2. Section 4.31 is amended by adding paragraph (h) to read:

§ 4.31 Acceptance for filing or rejection.

* * * * *

(h) Any timely petition for intervention submitted under § 1.8 of

this chapter relating to an application for preliminary permit for a water power project is deemed granted as of the date of filing unless the petition is opposed by any applicant under § 1.8(e) of this chapter or the Commission specifically denies or stays action on the petition within 15 days after the last date for filing petitions to intervene prescribed in the public notice issued under § 4.31(c)(2) of this chapter for the preliminary permit application. Intervention in any preliminary permit proceeding will not constitute intervention in the subsequent licensing proceeding.

3. Section 4.33 is amended by revising paragraph (a) to read as follows:

§ 4.33 Filing and disposition of conflicting applications.

(a) Any citizen, association of citizens, domestic corporation, municipality or state may submit for filing an application for a preliminary permit or license for a proposed water power project that would develop, conserve, and utilize, in whole or in part, the same water resources that would be developed, conserved, and utilized by a proposed water power project for which a preliminary permit or license application has already been accepted ("initial application").

(1) Except as provided in paragraph (a)(2) of this section, such an application ("competing application"), or a notice of intent to submit an application, must be submitted for filing on or before the last filing date for the filing of protests or petitions to intervene prescribed in the public notice issued under § 4.31(c)(2) of this chapter for the initial application.

(2) A notice of intent to file a competing application for preliminary permit may not be submitted for any proposed major project—existing dam, as defined in § 4.50(b)(2), or any proposed minor water power project, as defined in § 4.60(b)(4) of this chapter, which utilizes an existing dam.

Any competing application for preliminary permit for a proposed major project—existing dam or minor water power project which utilizes an existing dam must be submitted on or before the last date of the period for filing protests and petitions to intervene prescribed in the public notice issued under § 4.31(c)(2) of this chapter for the initial application.

* * * * *

4. Section 4.33 is amended in subparagraphs (g)(3) and (g)(4) by removing from both subparagraphs the words "taking into consideration the ability of each applicant to carry out its plans,".

5. Section 4.33 is amended by adding a new paragraph (i) to read:

§ 4.33 Filing and disposition of conflicting applications.

* * * * *

(i) Any municipal applicant or co-applicant that fails to provide evidence that the municipality is competent under applicable state and local laws, or opinions of the state attorney general, to carry on the business of developing, transmitting, utilizing, or distributing power will be considered a non-municipal applicant for the purpose of determining the disposition of competing applications.

6. Subpart D is amended by adding a new § 4.35 to read:

§ 4.35 Amendment of application.

If an applicant amends any filed preliminary permit or license application in order to revise the nature of the applicant or materially amend the proposed plan of development, the Commission will change the date of acceptance of the application [*See* § 4.31(e)] to the date on which the amendment is filed with the Commission and consider the amended application as a new filing for the purposes of disposing of competing applications under § 4.33 of this chapter and reissuing public notice of the application under § 4.31(c)(2) of this chapter. This section does not apply to corrections of deficiencies under § 4.31(d)(1) of this chapter.

7. Section 4.51 is amended in paragraph (a) by revising subparagraph (4) to read:

§ 4.51 Contents of application.

* * * * *

(a) *Initial statement.*

* * * * *

(4) [Name of applicant] is a [citizen, association of citizens, domestic corporation, municipality, or state, as appropriate]. If the applicant or any co-applicant is a municipality, the applicant must submit copies of applicable state and local laws, or opinions of the state attorney general evidencing that the municipality is competent under such laws or opinions to carry on the business of developing, transmitting, utilizing, or distributing power.

* * * * *

8. Section 4.81 is amended in paragraph (a) by revising subp[illegible] (4) to read as follows:

§ 4.81 Contents of application.

* * * * *

(a) *Initial statement.*

* * * * *

(4) [Name of applicant] is a[illegible] association of citizens, domes[illegible] corporation, municipality, or [illegible] appropriate]. If the applicant [illegible] applicant is a municipality, th[illegible] must submit copies of applic[illegible] and local laws, or opinions o[illegible] attorney general, evidencing [illegible] municipality is competent un[illegible] laws or opinions to carry on [illegible] business of developing, trans[illegible]itting, utilizing, or distributing pow[illegible]

* * * * *

¶ 32,115 Discontinuance of Certain Producer Reports and Related Form Nos. 108 and 314-B, and Reinstitution and Revision of Producer Filing Instructions

Issued February 18, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: By this Notice, the Federal Energy Regulatory Commission (Commission) proposes to eliminate in their entirety, FPC Form No. 108, "Rate Schedule Analysis on a Continuing Current Basis" (18 C.F.R. § 260.6), and FPC Form No. 314–B, "Annual Statement for Independent Producers Holding Small Producers Exemptions" (18 C.F.R. § 154.104).

In place of Form No. 108—which is composed of five separate schedules—the Commission would substitute the following reporting requirements:

In lieu of Schedule No. 502, "Independent Producer Rate Schedule Identification and Contract Data," and Schedule No. 503, "Independent Producer Rate Schedule Pricing Provisions and Actual Quality Data," the Commission proposes to require a computer output, at 18 C.F.R. § 154.94, "Form of Contract Summary to be Filed by All Applicants for a Certificate of Public Convenience and Necessity, Including Successors in Interest."

In lieu of Schedule No. 507, the Commission proposes the addition of a new section—18 C.F.R. § 250.14, "Initial Billing Statement or Notice of Change in Rate."

Schedule Nos. 501 and 505 are proposed to be entirely deleted.

Form No. 314–B is to be deleted in its entirety, and will be replaced by a "single statement" filing requirement that must be filed by any small producer who loses that status by producing more than 10 BCF per year.

The total reduction resulting from these changes in the reporting requirements is 68 percent. These reductions are made as part of an ongoing effort at the Commission to eliminate unnecessary reporting burdens and to update its forms, and are based upon the Commission's conclusion that the information proposed to be deleted is no longer needed by the Commission to carry out its regulatory duties.

DATE: Comments are due by April 6, 1981.

ADDRESS: Comments to this Notice should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM81–16.

FOR FURTHER INFORMATION CONTACT: Marvin Hugh, Chief, General Reports Branch, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 6410, Washington, D.C. 20426, Phone: (202) 357–8158.

Discontinuance of Producer Reports and Related Form Nos. 108 and 314–B, and Reinstitution and Revision of Producer Filing Instructions; Notice of Proposed Rulemaking

Issued February 18, 1981.

The Federal Energy Regulatory Commission (Commission) is engaged in

[illegible] an ongoing effort to eliminate unnecessary reporting burdens. This rulemaking would discontinue two of the Commission's reporting requirements [illegible]. Two of the five schedules in Form No. 108 would be deleted in their entirety (Schedule Nos. 502 and 505), as would be the supporting documents to the form. In place of two of the remaining three schedules (Schedule Nos. 502 and 503), the Commission proposes to reinstate a simplified reporting requirement. The remaining Form No. 108 schedule (Schedule No. 507) would be replaced by a new, shorter reporting requirement.

Form No. 314–B would be replaced by a requirement that a company file a single statement if it loses its small producer status.

The deletions and amendments proposed in this rulemaking would result in a significant reduction in the respondent's reporting burden; indeed, the Commission recently decided to suspend a number of filings under these two forms.[1]

I. Background

A. Form No. 108

Form No. 108 is prescribed by 18 C.F.R. § 260.8.[2] It requires the reporting of current information from large independent gas producers concerning deliveries and pricing of interstate gas sales. The form is designed for computer processing.

Form No. 108 currently consists of five schedules: No. 501, "Independent Producer Natural Gas Sales Summary"; No. 502, "Independent Producer Rate Schedule Identification and Contract Data" (Docket No. 503, "Independent Producer Rate Schedule Pricing Provisions and Actual Quality Data" (Docket No. [illegible]. [illegible] Independent Producer Annual Rate Schedule Sales Data", and No. 507, "Independent Producer Quarterly Report of Sales and Revenues". [illegible] of the information collected by Form No. 108 is used [illegible] are subsequently used in the administration of the Natural Gas Act (NGA) (15 U.S.C. §§ 717–717w). However, with the passage of the Natural Gas Policy Act (NGPA) (15 U.S.C. §§ 3301–3432), the biennial rate adjustments are no longer required. Therefore, the Form No. 108 data bank is obsolete, and should be eliminated.

1. *Schedule Nos. 501 and 505.* Schedule Nos. 501, "Independent Producer Natural Gas Sales Summary", and 505, "Independent Producer Annual Rate Schedule Sales Data", are annual gas sales, volume, and revenue reports. These reports are inadequate for NGPA compliance purposes in that they do not identify: (a) which first sales of gas from individual wells have been found by state agencies to fall into specific NGPA maximum lawful pricing categories,[3] and (b) which first sales of gas were subject to sections 104 and 106(a) of the NGPA. In addition, several of the wells dedicated to interstate sales contracts that have been subject to the NGPA well determination process are operated by either small producers or pipeline operators, and they are not required to file information on Schedule Nos. 501 and 505.

[illegible] The Commission's field audit program is [illegible] of an effective means of monitoring producer and pipeline compliance with the NGPA and with the Commission's regulations. Reliable, actual volume and revenue data for individual or company-wide sales may be obtained from producers and

[1] In anticipation of this Notice of Proposed Rulemaking, the Commission issued an order on May 5, 1988, to suspend, until further notice, the filing of Schedule Nos. 501 and 505 of Form No. 108, and the filing of Form No. 314–B (52 Fed. Reg. 16660, May 20, 1988).

[2] Form No. 108 was instituted by Order No. 548, Docket No. RM–80–40, Fed. Reg. Stats. Regulations ¶ 30,255, and revised by Order No. 548–A, Docket No. RM79–76–40, Fed. Reg. 43277, August 16, 1977.

[3] See §§ 102, 103, 107 and 108 of the NGPA.

pipelines as needed by the Commission or by the Energy Information Administration (EIA) through specific data requests. For these reasons, the Commission proposes [illegible]

[illegible]

Schedule Nos. 502 "Independent Producer Rate Schedule and Contract Data" and 503 "Independent Producer Rate Schedule Pricing Provisions and Actual Quality Data" collect summaries of contract data. They are required to be filed every time a producer submits a new contract or a contract amendment.

While passage of the Natural Gas Policy Act has made the continued filing of much of the Form No. 108 data unnecessary, sections 4 and 7 of the Natural Gas Act still require that certain certificate and rate filings be made for gas that is "committed or dedicated to interstate commerce" within the meaning of section 2[18] of the NGPA.

Therefore, in lieu of Schedule Nos. 502 and 503, the Commission proposes, in effect, to reinstate § 250.5 of the Commission's regulations, to provide for Format No. FERC 558, "Contract Summary to be Filed by all Applicants for Certificates of Public Convenience and Necessity, Including Successors in Interest." Section 250.5 had been deleted by the Commission Order which established Form No. 108. (See footnote no. 2 above.) This revised § 250.5 would include certain NGPA pricing data which is currently provided for in Schedule Nos. 502 and 503. It would also include a limited number of new data elements which are essential to a [illegible] application. [illegible] would [illegible] purposes. [illegible] however, be designed for human (*i.e.*, non-computer) use. It would also represent an 82 percent reduction in data elements from Schedule Nos. 502 and 503, and would eliminate a considerable reporting burden for affected respondents.

[illegible] Schedule No. 507, "Independent Producer Rate Change or Initial Billing Statement" [illegible] a change in the rate which a producer proposes to make in the filed rate under section 4 of the NGA.[1]

The Commission believes that the data in Schedule No. 507 could be reported in a simpler format. Thus, new Format No. FERC 559, "Independent Producer Rate Change or Initial Billing Statement", is proposed to be set out at § 250.14 of the Commission's regulations. Format No. FERC 559 would collect some of the same data as Schedule No. 507. Certain new elements would be included to conform to requirements of the NGPA. However, as a result of the simplification of the format and deletion of items which are not essential to the report, a 30 percent net reduction in data elements would result, as compared to Schedule No. 507. Format No. FERC 559 would also be designed for human (*i.e.*, non-computer) use. Finally, the new format could be used for either of two purposes, *i.e.*, as an Initial Billing Statement, or as a Notice of Change in Rate Filing.

B. Form No. 516-B

Section 154.104 of the Commission's regulations requires that small producers file annual reports of [illegible] sales. The data are submitted on [illegible] to identify small producers and their affiliates whose combined annual jurisdictional sales exceed 10 million Mcf, so that such certificates may be cancelled with respect to future sales.

[1] Many changes in rate filings have been eliminated under the blanket abandonment procedures adopted in Order No. 15 (issued November 17, 1978, 43 Fed. Reg. 54778, November 28, 1978, amended by Order No. 15-A, issued December 20, 1978, 44 Fed. Reg. 1186, January 4, 1979, and in Order No. 15-B, issued March 27, 1979, 44 Fed. Reg. 19048, April 3, 1979).

Small producer status is terminated as of April 1 of the year immediately following the calendar year in which a producer's jurisdictional sales (including affiliate sales) exceeded 10 million Mcf. Small producer status is also lost if a small producer merges with, is acquired by, or otherwise become affiliated with: (a) another producer, and the total jurisdictional sales of such parties exceeds 10 million Mcf, or (b) a Class A pipeline company. This annual report currently constitutes notice to the Commission of such excess sales. (*See* § 157.40 (a)(1) and (d).

Since enactment of the Natural Gas Policy Act, which prescribes the maximum statutory prices for producer sales in both interstate and intrastate markets, the annual reporting requirements for interstate small producer sales are of minimal value to the Commission's regulatory responsibilities. Therefore, the Form No. 314–B and the reporting burden that it represents could be eliminated, without any apparent detriment.

The Commission accordingly proposes to require that a company report a loss of small producer status. This information would, however, be required merely in the form of a simple statement to the Commission that the company's sales have exceeded 10 million Mcf during the previous calendar year.

II. Summary of Changes

A. Form No. 108

The Commission proposes to delete the "Form No. 108" and the following supporting documents to the Form in their entirety:

Schedule Nos. 501 and 505; the Cover Sheet; Table of Contents; Schedule 0000. "Footnotes to FPC Public Use Schedules"; Directions for Submitting Completed Schedules to the FPC; Attestation; Index; and the Register of Data Standards.

Schedule Nos. 502 and 503 would be replaced by a single noncomputer format, Format No. FERC 558, set out at § 250.5 of the Commission's regulations.

The following changes in the reporting requirement would result:

Deletions

Current Schedule Nos. 502 and 503

Respondent Code
Submission Period
Page Footnote
Original—Revision
Page of Pages
FERC Rate Schedule Number
Multiple Analysis Code
Reason for Multiple Analysis
Supplement Number
Proposed Effective Date

Current Schedule No. 502

Contract Date
Contract Ratification Date
Contract Renegotiation Date
Well Spud-In Date Category
Buyer Code
First State, First County Code
First State, Second County Code
First FPC Area Code
Second State, First County Code
Second State, Second County Code
Second FPC Area Code
Supplement Filing Date
Supplement Effective Date
Supplement Effective Date—Estimated-Indicator
Supplement Effective Date—Indefinite
Type Supplemental Filing
Rate Schedule Effective Date—Actual
Rate Schedule Effective Date—Indefinite
Contract Initial Term
Contract Term Extended
Contract Term—Date From
Contract Term—Indefinite Date From
Contract Measurement Pressure Base
Analysis Code Pressure Base
Type of Gas Seller
Status of Contract
Maximum Contract Delivery Pressure—First Set
Maximum Contract Delivery Pressure Indicator—First Set
Minimum Contract Delivery Pressure—First Set
Minimum Contract Delivery Pressure Indicator—First Set
Maximum Contract Delivery Pressure—Second Set
Maximum Contract Delivery Pressure Indicator—Second Set
Minimum Contract Delivery Pressure—Second Set
Minimum Contract Delivery Pressure Indicator—Second Set
Processing Rights

Actual Delivery Points
Actual Delivery Points
Actual Measurement Point
Actual Measurement Point
Actual Measurement Point
Take-or-Pay Provision
Accelerated Take Provision
Btu Requirements, Minimum
Btu Requirements, Price Adjustable Below
Btu Adustment, Type Downward
Btu Requirements, Maximum
Btu Requirements, Price Adjustable Above
Btu Adjustment, Type Above Maximum Total Sulphur
Maximum Sulfur Commercially Free Indicator
Maximum Hydrogen Sulfide
Maximum Water
Maximum Water Abbreviation
Maximum Total Diluent
Maximum CO_2, Percent
Maximum Oxygen, Percent
Maximum Nitrogen, Percent
Maximum Liquid Hydrocarbons
Maximum Liquid Hydrocarbons Indicator
Purity Clause Indicator
FERC Field Plant Code
Field Depth Limitation
Effective Date of Seller—Buyer Change
Seller Buyer Code
Name Change Indicator
Type of Change Indicator
Type Identification Change Indicator
Rate Schedule Name Suffix
Prior/Present Rate Schedule Identification Number

Current Schedule No. 503

Revenue Sharing Clause
Spiral Escalation Clause
Liquid Revenue Clause
Favored Nation Clause
FERC Area Rate Clause
Area Rate Clause, Actual Date From
Deregulation Clause
Tax Reimbursement, Percent
Maximum Tax Reimbursement
Percent Gas Well Gas
Percent Casinghead Gas
Percent Residue Gas
Residue Gas Mixture—Gas Well
Residue Gas Mixture—Casinghead
Delivery Pressure Indicator
Actual Average Btu
Average Btu Content Indicator
Fixed Increase—Actual Date
Fixed Increase—Indefinite Date
Fixed Increase—Base Rate
Type Impurity
Impurity Content
Impurity Content Indicator
Waiver of Price Renegotiation/Redetermination
Price Renegotiation/Redetermination Indicator
Current Ratio to Reserves Denominator
Estimated Annual Sales Volume
Price Redetermination Date, Actual
Price Redetermination Date, Indefinite
Historical Annual Sales, Year
Historical Annual Sales, Volume

Seller Additive Charge—Type, Seller Additive Charge—Amount, Buyer Deductive Charge—Type, and Buyer Deductive Charge—Amount would be combined into one element in Format No. FERC 558.

Additions

Person Responsible for Application
Location of Sale—State and County Name
Estimated Sales Volume—Monthly
Assignor's FERC Docket Nos.
Proposed Disposition of Rate Schedule
Suspension Docket Number
Price Subject to Refund, Dollars/MMBtu
Date Price Made Effective Subject to Refund
Estimated Amount Subject to Annual Refund
Bond or Undertaking Intention

Schedule No. 507 would be replaced by a non-computer format, Format No. FERC 559, set out at § 250.14 of the Commission's regulations. The following changes in the reporting requirements would result:

Deletions

Respondent Code
Submission Period
Page—Footnote
Original—Revision
Page of Pages
Multiple Analysis Code
Reason for Multiple Analysis
FPC Rate Schedule Supplement Number
Type Rate Schedule Identification
Buyer Code
State Abbreviation
County Code
Field/Plant Code
Proposed Effective Date—Indefinite
Proposed Revenue Differences—DOL
Tax Reimbursement, CTS/Mcf
Other Charges, CTS/Mcf
Other Charges—Dehydration, CTS/Mcf
Other Charges—Compression, CTS/Mcf
Other Charges—Treating, CTS/Mcf
Other Charges—Other, CTS/Mcf
Line Sequence Number

Type of Rate Change and Other Type of Rate Change would be combined into one element in format No. FERC 559.

Additions

Total Rate, CTS/MMBtu
Covered by Affidavit under § 154.94(h)
Rate Under Sections 102(d) or 108 of NGPA
FERC Notice of Determination Control Number
Effective Date of Determination
Date

County Name, and State Name requirements which are currently prescribed in Schedule No. 507 would be modified for inclusion in Format No. FERC 559.

B. Form No. 314–B

Form No. 314–B would be deleted in its entirety. Only a statement to the effect that annual producer sales have exceeded 10,000,000 Mcf would be required to be filed by the producer, with the Commission and with its purchasers.

III. Certification of no Significant Economic Impact

The Regulatory Flexibility Act (RFA),[5] requires certain statements, descriptions, and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities."

Pursuant to section 605(b) of the RFA, the Commission finds that the provisions of that Act do not apply to this rulemaking. If promulgated, this rulemaking would simplify the reporting requirements for independent natural gas producers, by eliminating two cumbersome reports, Form No. 108, "Rate Schedule Analysis on a Continuing Current Basis", and Form No. 314–B, "Annual Statement for Independent Producers Holding Small Producer Exemptions".

Two of the five schedules in Form No. 108 would be deleted in their entirety, two others would be replaced by Format No. FERC 558, and another schedule would be replaced by Format No. 559. Format Nos. FERC 558 and 559 would be simplified, noncomputer reporting requirements which would result in a significant reduction in respondent reporting burdens. Neither the current Form No. 108 nor the proposed revised formats, Format Nos. FERC 558 and 559, impose any requirements upon "small producers" (*i.e.*, independent producers of natural gas who are not affiliated with a Class A natural gas pipeline company and whose total "jurisdictional sales" on a nationwide basis, together with sales by affiliated producers were not in excess of 10,000,000 Mcf during the preceding calendar year) (*see* 18 C.F.R. 157.40(a)). Only those independent producers whose sales exceed 10,000,000 Mcf during the preceding calendar year would submit these filings.

Form No. 314–B would be replaced by a "single statement" filing which would be required of any small producer who loses that status by producing more than 10,000,000 Mcf per year.

As such, this rulemaking does not impose any regulatory or administrative burden upon small entities nor does it require an expense of resources by such entities. For these reasons, the Commission hereby certifies that this rulemaking, if promulgated, would not have a significant impact on a substantial number of small entities.

IV. Written Comment Procedures

The Commission invites interested persons to submit written data, views and other information concerning the matters set out in this Notice. An orginal and 14 copies of such comments should be filed with the Commission by April 6, 1981. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM81–16.

All written submissions will be placed in the Commission's public files and will be available for public inspection in the

[5] 5 U.S.C. §§ 601–612 (Pub. L. 96–354).

Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426 during regular business hours.

(Department of Energy Organization Act, 42 U.S.C. 7101–7352; Natural Gas Policy Act, 15 U.S.C. 3301–3432, Natural Gas Act, 15 U.S.C. 717–717w; Regulatory Flexibility Act, Pub. L. No. 96–354; E.O. 12009, 3 C.F.R. 142)

In consideration of the foregoing, the Commission proposes to amend Parts 154, 157, 250 and 260, of Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,
Secretary.

1. Section 154.92 is amended by revising the second sentence of paragraph (a) and the second sentence of paragraph (b) to read as set forth below; and removing paragraph (e) in its entirety.

PART 154—RATE SCHEDULES AND TARIFFS

§ 154.92 Filing of rate schedules by independent producer.

(a) * * * To each such rate schedule, there shall be attached a billing statement, in the format specified in § 250.14.

(b) * * * To each such rate schedule there shall be attached a statement, in the format specified in § 250.14, which shows the estimated sales and billing for the first month of service, in sufficient detail to show the method of billing and price used.

* * * * *

(e) [Removed]

* * * * *

2. Section 154.94 is amended by revising paragraph (f), and Appendix A in the fourth paragraph of Item II of the Instructions for Competing Exhibit A to read as follows:

§ 154.94 Changes in rate shcedules.

* * * * *

(f) Notice of change in rate level. An independent producer who is proposing a contractual change in rates, charges, etc., shall file the information specified in § 250.14.

* * * * *

Federal Energy Regulatory Commission

Appendix A to § 154.94

* * * * *

Exhibit A

* * * * *

Instructions for Completing Exhibit A

* * * * *

II. *Specific Instructions. Respondent Name and Code:*

* * * * *

Applicable Just and Reasonable Rate Previously Established Under the NGA: Enter either the base rate (Mcf at 14.73 psia) reflected in the last notice of change in rate submitted for the vintage involved or the base rate reflected in the initial billing statement. *See* § 250.14 of this chapter.

* * * * *

§ 154.104 [Removed]

3. Section 154.104 is removed in its entirety.

4. Section 157.24 is amended by revising the first sentence of paragraph (a) to read as follows:

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

§ 157.24 Contents of application.

(a) Every application for a certificate of public convenience and necessity required under § 157.23 shall be filed with the Commission and shall contain, in the form specified in § 250.5, a summary of each contract for the sale or transportation of natural gas for which a certificate is requested. * * *

5. Section 157.40 is amended in paragraph (a)(1) by revising the last two sentences of the second paragraph, which begins as set forth below, to read as follows:

§ 157.40 Exemption of small producers from certain filing requirements.

(a) Definitions. (1) * * *

Upon termination of small producer status * * *

If such termination occurs as a result of merger or affiliation, the producer shall give notice thereof to its

purchasers and to the Commission within 30 days of the effective date of such occurrence. If such termination occurs as a result of sales having exceeded the 10,000,000 Mcf limitation during a calendar year, the producer shall give notice thereof to its purchasers and to the Commission by letter to be submitted on or before April 1 of the following year.

* * * * *

6. A new § 250.5 is added to read as follows:

PART 250—FORMS

§ 250.5 Contract summary to be filed by all applicants for certificates of public convenience and necessity, including successors in interest. (See § 157.24(a) of this chapter.)

Note.— All applicants shall complete Part I. An applicant who is an assignee (including farmout) filing as a successor shall also complete Part II–A and Part II–B if the related rate schedule is under suspension, if the rate is in effect subject to refund, or if the sale is being made by the assignor under temporary certificate with a rate refund condition. The reporting pressure base is 14.73 psia.

Date ———

Part I

(1) Name of applicant ———
(2) Person responsible for application:
(a) Name and title ———
(b) Mailing address ———
(c) Telephone No ———
(3) Name of purchaser ———
(4) Are applicant and purchaser affiliated?
No ———
Yes ———
(5) Location of sale:
(Field, County, State) ———
(6) Type of application [1] ———
(7) Date of contract ———
(8) Total price in dollars per MMBtu (including all adjustments and tax reimbursement)—
(9) Specify adjustments included in total price per MMBtu in (8) above [2] ———
(10) Estimated sales volumes (Mcf per month)
(11) Delivery pressure ———
(12) Delivery point e.g., wellhead, plant tailgate, central point in field, etc ———
(13) Other special conditions affecting price—
(14) Advance payments:
Yes ———
No ———

Part II–A

(15) Assignor ———
(16) Description of service to be continued:
(a) FERC Docket No.(s) under which assignor was originally authorized: ———
(b) Proposed disposition of assignor's FERC Gas Rate Schedule(s) ———

Part II–B

(17) Suspension Docket No ———
(18) Price currently being collected subject to refund (in dollars per MMBtu ———
(19) Date price made effective subject to refund
(20) Estimated amount subject to possible annual refund $——
(21) In addition to the refund obligation requred by § 154.92(d)(3), does assignee intend to file bond or undertaking to assure total refund: (a) from the date increased rate of assignor became effective subject to refund or (b) from date operation commenced under assignor's temporary certificate containing a refufnd condition? Yes——
No——

§ 250.11 [Removed]

7. Section 250.11 is removed it its entirety.

8. A new § 250.14 is added to read as follows:

§ 250.14 Independent producer rate change or initial billing statement. (See §§ 154.92 and 154.94)

Note.—This format is to be used to file either a Notice of Change in Rate or an Initial Billing Statement by checking the appropriate box and answering the applicable questions. Applications filed to collect Natural Gas Policy Act rates must include rate information items (9)(a) through (f) and also include a statement, under oath, stating that in addition to collecting NGPA rates as shown, the filing party will be reimbursed only for taxes actually paid, to the extent contractually authorized. Do not include tax reimbursement data for NGPA rates on the form. Applications filed to collect rates at Natural Gas Act or contract rate levels must include tax items (9)(a) through (e). Applicable tax reimbursement should be included under item (9)(d). Rates should be shown in dollars to three decimal places. The reporting pressure base is 14.73 psia.

[1] Specify whether initial service, add acreage, delete acreage, continue service of predecessor, farmout, or other. If "other", give details.

[2] Specify each type of adjustment (e.g. gathering, dehydration, compression, liquefiable hydrocarbons, etc.) and each related adjustment amount in price per MMBtu reflected in the total price.

Check One: Producer Rate Change (§ 154.94)
☐ Initial Billing Statement (§ 154.92) ☐
(1) Name of Producer _____
(2) FERC Gas Rate Schedule No. _____
(3) Name of Buyer _____

(4)Location:
(a) Field _____
(b) County _____
(c) State _____
(5) Basic Contract Date _____
(6) Proposed Effective Date _____
(7) Contract Basis _____
(8) Regulation Section (type of change) _____
(9) Rate information:

	Current	Proposed
(a) Base rate ($/Mcf)	$	$
(b) Btu adjustment		
(c) Gathering allowance		
(d) Other (explain)		
(e) Total rate ($/Mcf)		
(f) Total rate ($/MMBtu)		

(10) Average Btu content (Btu/cu.ft.) _____
(11) Estimated annual sales volume (Mcf) _____
(12) Are future escalations to be covered by affidavit filed under § 154.94(h)? _____
(13) Is the application for a rate under sections 102(d) or 108 of NGPA? _____
If yes, what is (a) The FERC Notice of Determination Control No.? _____
(b) The effective date of final determination? _____
(14)Remarks:
(15) Person responsible for this filing:
(a) Name and title _____
(b) Signature _____
(c) Address:
Street No _____
City _____
State _____
Zip _____
(d) Telephone No _____
(e) Date _____

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

§ 260.6 [Removed]

9. Section 260.6 is removed it its entirety.

¶ 32,116 Application for Authorization of the Issuance of Securities or the Assumption of Liabilities

46 F. R. 15513 (March 6, 1981)

18 CFR Parts 34 and 131

[Docket No. RM81-18]

Application for Authorization of the Issuance of Securities or the Assumption of Liabilities

Issued: February 27, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: By this Notice, the Federal Energy Regulatory Commission (Commission) proposes to revise its regulations at 18 CFR Part 34—Application for Authorization of the Issuance of Securities or the Assumption of Liabilities. Among the changes would be various clarifications, simplifications, reductions and deletions to the provisions of this Part. The changes are proposed as part of the Commission's effort to update its reporting and filing requirements and to eliminate unnecessary reporting burdens for those entities which file applications or reports with the Commission pursuant to Part 34.

DATE: Comments are due by March 30, 1981.

ADDRESS: Comments to this Notice should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 and should reference Docket No. RM81-18.

FOR FURTHER INFORMATION CONTACT:

Robert E. Hildebrand, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3408N, Washington, D.C. 20426, (202) 357-9184.

I. Background

The Federal Energy Regulatory Commission (Commission) proposes to revise 18 CFR Part 34—Application for Authorization of the Issuance of Securities or the Assumption of Liabilities. Part 34 applies to any issuance of a security or assumption of obligation or liability by a public utility or licensee for which approval must be obtained from the Commission pursuant to sections 19 and 20, and 204 of the Federal Power Act (FPA) (16 U.S.C. 792-828c).

The proposed changes to Part 34 reflect a new evaluation of the data needed by the Commission to carry out its regulatory functions. As a result, certain clarifications, simplifications, reductions and deletions have been made to the requirements in Part 34. The changes should facilitate the processing of security applications as well as reduce the filing and reporting burdens upon the affected utilities.[1]

II. Summary of Proposed Changes

Pursuant to this Notice of Proposed Rulemaking, Part 34 would be completely restructured and descriptions of the requirements therein would be clarified and simplified for ease of compliance.

The changes to Part 34 would include the following:

New Sections

§ 34.1.

(a) [Current § 34.1]—no substantive change.

[1] All references to "utilities" herein include public utilities, licensees and other entities.

(b) [New]—provides definitions for "utility," "securities," and "issuance or placement of securities," for purposes of this Part.

(c)(1) [New]—clarifies the exemption from Commission regulation of the issuance of securities by utilities where such issuances are regulated by an appropriate State agency; this provision, which is consistent with current Commission practice, requires that the State agency give express *advance* approval of any proposed issuance of securities.

(2) [Current § 34.20]—clarifies the exemption from Commission regulation of the issuances of securities where such securities are short-term.

(3) [New]—clarifies the exemption for certain non-utility-owned qualifying facilities which are otherwise exempt from Commission regulation. In a related rulemaking, Docket No. RM81-2, the Commission is determining whether and to what extent *utility*-owned geothermal facilities should be exempt from Part 34 regulation, in accordance with sections 201 and 210 of the Public Utility Regulatory Policies Act, as amended by the Energy Security Act of 1980. Commenters are specifically requested to address this matter.

§ 34.2.

(a)(1) [Current § 34.1a(a)]—clarifies competitive bidding requirements and provides exemptions from such requirements.

(2) [Currently within § 34.1a(c)]—clarifies and simplifies competitive bidding procedures.

(b)(1) [Currently within § 34.2(f)(2)]—clarifies the requirements for negotiated placement of securities.

(2) [Current § 34.2(f)]—clarifies the Commission's requirements for negotiated placements of securities.

(c) [Current § 34.1a(b)]—no substantive change.

[Current § 34.1a(c) is removed.]

§ 34.3 [Current § 34.2].

(a)–(c) [Current § 34.2(a)–(c)]—no substantive change.

(d) [New]—requests date by which Commission action on the application is sought.

(e)(1)–(4) [Current § 34.2(d)(1)–(4)]—no substantive change.

(5) and (6) [New]—requires stock exchange information and data in support of an exemption from competitive bidding requirements. This information is currently reported by telephone.

[Current paragraph § 34.2(d)(5) is removed.]

(f) [Current paragraph § 34.2(e)]—simplifies the requirements for a description of the method used for issuances, sales, or assumptions. [Current paragraphs (1) through (4) are removed.]

[Current paragraphs § 34.2 (f) and (g) are removed.]

(g) [Current paragraph § 34.2(h)]—no substantive change.

[Current paragraph § 34.2(i) is removed.]

(h) [Current paragraph § 34.2(j)]—simplifies the requirements for reporting the purpose for which the securities are to be used.

[Current paragraphs § 34.2(k), (l) and (m) are removed.]

(i) [Current paragraph § 34.2(n)]—provides that the statement concerning information about the application which must be filed with other regulatory bodies, is only required if such information must be filed with a State regulatory body.

(j) [Current paragraph § 34.2(o)]—no change.

[Current paragraph § 34.2(p) is removed.]

(k) [New]—requires details concerning bond indenture(s) or other limitations on interest and dividend coverage and the effects of each limitation. This information is currently reported by telephone.

(l) [New]—requires a brief summary of rate changes placed in effect during or subsequent to the date of the financial statements. This information is currently reported by telephone.

(m) [Current paragraph § 34.2(q)]—no substantive change.

(n) [New]—clarifies the requirement to include appropriate exhibits with each application.

§ 34.4 [Current § 34.3].

Exhibit A. [Current *Exhibits A* and *B.*]—adds a note which provides that, in certain instances, specific references may be made to the applicant's charter or bylaws, in lieu of supplying the entire documents.

[Current *Exhibit C* is removed.]

Exhibit B. [Current *Exhibit D*]—no substantive change.

[Current *Exhibits E* and *F* are removed.]

Exhibit C. [Current *Exhibit G*]—no substantive change.

Exhibit D. [Current *Exhibit H*]—no substantive change.

[Current *Exhibits I, J* and *K* are removed.]

Exhibit E. [Current *Exhibit L*]—no substantive change.

[Current *Exhibit M* is removed.]

Exhibit F. [Current *Exhibit N*]—removes the requirement to attach a copy of each application and exhibit filed with a State agency, and a certified copy of action taken thereon.

Exhibit G. [Current *Exhibit O*]—simplifies and clarifies the requirement concerning invitations for proposals to purchase or underwrite the securities to be issued.

[Current *Exhibit P* is removed.]

Exhibit H. [New]—requires a summary tabulation of all proposals received for negotiated placement of securities, including certain details about such securities. This information is currently reported in individual data requests. *Exhibit H* also consolidates data requirements concerning identification of certain persons with whom negotiations took place, and justification of a utility's intention to accept a particular offer.

Exhibit I. [Current *Exhibit Q*]—adds, for clarification purposes, a new requirement (Item 6) concerning the deletion of a significant item or change in total estimated cost of a facility. This information is currently reported in individual data requests.

[Current *Exhibit R* is removed.]

Exhibit J. [New]—adds a requirement showing the applicant's estimate of its peak load and generating capacity for the next five years; and any plans for changing capacity. This information is currently reported in individual data requests.

§ 34.5 [Current § 34.4]—no substantive change.

§ 34.6 [Current § 34.5]—no substantive change.

§ 34.7 [Current § 34.6]—deletes the requirement for an applicant to file with the Commission, a copy of an application for each State affected, in addition to such copies required for Commission purposes.

§ 34.8 [Current § 34.7]—no substantive change.

§ 34.9 [Currently within § 34.2]—clarifies the application fee requirement.

§ 34.10 [Current § 34.8]—reduces the amount of data to be filed in a securities report to the Commission and revises the time period for which information is required.

[Current §§ 34.9 through 34.24 are removed. The data in § 34.9, concerning Commission action on applications for issuance of securities, is essentially summarized elsewhere in Part 34. § 34.10, which requires a disclaimer with respect to Commission authority is duplicated in Commission orders and is, therefore, not required here. §§ 34.20 through 34.24, concerning the requirements for a certificate of notification, are summarized in § 34.1(c).]

Certain conforming changes would be made to § 131.43, *Report of securities issued,* and to § 131.50, *Certificate of Notification.* Certain details concerning outstanding securities would also be deleted from § 131.50, and the requirement would be added to report date of State authorization and applicable docket number.

III. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) [3] requires certain statements, descriptions and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities."

Pursuant to section 605(a) of the RFA, the Commission finds that the provisions of that Act do not apply to this rulemaking. If promulgated, this rulemaking would simplify and clarify the provisions of 18 CFR Part 34. Part 34 sets out the requirements for applications filed with the Commission by public utilities, licensees and other entities who propose to issue securities or assume liabilities. Virtually all entities which have recently filed such applications with the Commission are "Class A" untilities and licensees, which have annual electric operating revenues of $2,500,000 or more. (*See* Item 1.A. of the General Instructions at 18 CFR Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (Class A and Class B)). The large size of these filing entities indicates that they are not the type of affected "small entities" that RFA procedures seek to protect.

The coverage of Part 34 is not restricted to issuances or assumptions solely by Class A utilities. Part 34 covers all issuances and assumptions by any utility, depending on whether an agency in a State in which the utility is organized or operates, regulates such issuances, and whether the issuances are of such a short-term nature as to be exempt from Commission regulation under section 204(e) of the Federal Power Act. Even proposed issuances or assumptions by the relatively smaller Class B utilities (*i.e.*, those with revenues between $1,000,000 and $2,500,000) may be subject to the provisions of Part 34. Nevertheless, both Class A and Class B utilities are considered "large" by Commission standards and large in comparison to many of the smaller municipally-owned utilities or rural cooperatives.

This rulemaking will not impose any substantial regulatory or administrative burden upon small entities, and, therefore, does not require any expenditure of resources by such entities. For these reasons, the Commission hereby certifies that this rulemaking, if promulgated, would not have a significant impact on a substantial number of small entities.

IV. Written Comment Procedures

The Commission invites interested persons to submit written data, views and other information concerning matters set out in this Notice. In particular, the Commission requests that comments address the following questions:

1. What is the current reporting burden, in dollars and hours, associated with the filing of an application pursuant to Part 34?
2. What decrease (increase) in reporting burden (if any) would occur as a result of the proposed revisions to Part 34?

All comments in response to this Notice should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should refer to RM81-18. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. E.S.T. March 30, 1981, will be considered by the Commission in promulgating the final regulations.

All written submissions will be placed in the Commission's public file and will be available for public inspection during regular business hours in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

(Department of Energy Organization Act, 42 U.S.C. 7101-7352; Federal Power Act, 16 U.S.C. 792-828(c); Regulatory Flexibility Act,

[3] 5 U.S.C. 601-612 (Pub. L. 96-354, September 19, 1980).

Pub. L. No. 96-354, September 19, 1980; E.O. 12009, 3 CFR, 1977 Comp., p. 142)

In consideration of the foregoing, the Commission proposes to revise Part 34 and amend Part 131 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Part 34 is revised to read as follows:

PART 34—APPLICATION FOR AUTHORIZATION OF THE ISSUANCE OF SECURITIES OR THE ASSUMPTION OF LIABILITIES

Sec.

34.1 Applicability; definitions; exemptions in case of certain State regulation, certain short-term issuances, and certain qualifying facilities.
34.2 Competitive bidding requirements; negotiated placements; exemptions.
34.3 Contents of application for competitive bids or negotiated placements.
34.4 Required exhibits.
34.5 Additional information.
34.6 Form and style.
34.7 Number of copies to be filed.
34.8 Verification.
34.9 Filing fee.
34.10 Reports.

Authority: Federal Power Act, Secs. 3(16), 19, 20, 41 Stat. 1063, 1073; secs. 203, 204, 305, 308, 309, 49 Stat. 849, 850, 856, 858; 16 U.S.C. 796(16), 812, 813, 824b, 824c, 825d, 825g, 825h, unless otherwise noted.

Cross References: For rules of practice and procedure, see Part 1 of this chapter. For forms under rules of practice and regulations, Federal Power Act, see Part 131 of this chapter.

§ 34.1 Applicability; definitions; exemptions in case of certain State regulation, certain short-term issuances, and certain qualifying facilities.

(a) *Applicability.* The requirements of this Part shall apply to applications for authorization from the Commission to issue securities or assume an obligation or liability which are filed by:

(1) Licensees and other entities pursuant to sections 19 and 20 of the Federal Power Act (41 Stat. 1073, 16 U.S.C. 812, 813) and Part 20 of the Commission's regulations; and

(2) Public utilities pursuant to section 204 of the Federal Power Act (49 Stat. 850, 16 U.S.C. 824c).

(b) *Definitions.* For the purposes of this Part:

(1) The term "utility" shall mean a licensee, public utility, or other entity seeking authorization under sections 19, 20 or 204 of the Federal Power Act, unless otherwise specified;

(2) The term "securities" shall include any note, stock, treasury stock, bond, or debenture or other evidence of interest in or indebtedness to a utility; and

(3) The term "issuance or placement of securities" shall mean issuance or placement of securities, or assumption of obligation or liability, unless otherwise specified.

(c)(1) *Exemption if State regulates securities prior to issuance.* A utility which is organized and operating in a State under the laws of which its security issuances are regulated by a State agency, shall be exempted from the provisions of sections 19, 20, or 204 of the Federal Power Act, as the case may be, and from the provisions of this Part: *Provided, however,* That such State agency is required to exercise such regulatory authority with respect to the issuance of such securities prior to such issuance, and that such utility must obtain express authorization from such State agency prior to the issuance of such securities.

(2) *Exemption for short-term notes or drafts.* Pursuant to section 204(e) of the Federal Power Act, the issuance, renewal, or assumption of liability on a note or draft:

(i) Maturing not more than one year the date of such issuance, renewal, or assumption of liability, and

(ii) Aggregating (together with all other then outstanding notes and drafts of a maturity of one year or less on which such utility is primarily or secondarily liable) not more than 5 per cent of the total of the other securities of the utility then outstanding, including:

(A) In the case of securities having a par value, such par value, and

(B) In the case of securities having no par value, the fair market value of such securities as of the date of issuance, renewal or assumption of such note or draft, is exempt from Commission regulation pursuant to this Part: *Provided, however,* That within 10 days after any such issuance, renewal, or assumption of liability, the utility shall file with the Commission a certificate of notification, in the form set forth in § 131.50 of this chapter.

(3) *Exemption for certain qualifying facilities.* Any cogeneration or small power production facility which is exempt from sections 19, 20 or 204 of the Federal Power Act pursuant to § 292.601 of this chapter shall be exempt from the provisions of this Part.

§ 34.2 Competitive bidding requirements; negotiated placements; exemptions.

(a)(1) *General requirement for competitive bidding; exemptions.* Every issuance by a utility of a security subject to sections 19, 20 or 204 of the Federal Power Act shall be made only after public invitation for and acceptance of competitive bids for such securities in accordance with the requirements of this Part, except when:

(i) The securities are to be issued to holders of existing securities on a pro-rata basis;

(ii) The securities are to be issued to a commercial bank, insurance company or similar institution and are not for resale to the public: *Provided, however,* That no fee or commission is paid to any third party for negotiating the transaction (except an associated service company charging only its costs of service);

(iii) The securities to be issued have a maturity of one year or less; or

(iv) The issuance of the securities, if not otherwise exempt from the competitive bidding requirements under paragraph (a)(1)(i), (ii), or (iii), is nevertheless exempted by the Commission pursuant to a utility's request, under paragraph (b)(2), for authority to negotiate for placement of securities, in lieu of seeking competitve bids:

Provided, however, That the Commission may deny any such exemption from competitive bidding upon a finding that a non-competitive placement is not consistent with the public interest.

(2) *Competitive bid application and Commission action thereon.* A utility which proposes to issue securities subject to this Part according to competitive bidding procedures shall file an application with the Commission under this Part for authority to make such issuances. Upon the receipt of such authorization, the utility may, without further Commission action, invite bids and issue the securities: *Provided, however,* That:

(i) Such proposed bids as may be received in response to the public invitation shall not be opened at any time or place other than as specified in the invitation;

(ii) The duly authorized representative of any person making any such proposed bid shall be entitled to be present at the opening of such proposed bids and may examine each such proposed bid submitted;

(iii) The invitation shall refer to the prohibitions set forth in paragraph (c);

(iv) At least two of the bids received shall meet the conditions set forth in the invitation for bids; and

(v) (A) The bid which is accepted shall provide the utility with the greatest overall proceeds, or be the least costly of the proposals obtained, or

(B) If the utility intends to accept a bid other than that described in paragraph (a)(2)(v) (A), the utility shall before accepting such a bid:

(*1*) File with the Commission such further justification as the Commission may require, in support of such utility's intention to accept such other bid, and

(*2*) Obtain Commission approval to accept such other bid.

(b) *Negotiated placements.*

(1) *Negotiated placement application pursuant to paragraph (a)(1)(i), (ii) or (iii), and Commission action thereon.*

Any utility which is exempt from the competitive bidding requirements under paragraph (a)(1)(i), (ii) or (iii) shall submit an application for negotiated placement of securities pursuant to § 34.3. Upon the Commission's authorization to such utility for negotiated placement of such securities, the utility may, without further Commission action, make such placement.

(2) *Negotiated placement application pursuant to paragraph (a)(1)(iv), and Commission action thereon.*

(i) A utility which requests authority to issue securities by negotiation pursuant to paragraph (a)(1)(iv) shall:

(A) File for, and obtain an exemption from, the Commission's competitive bidding requirements prescribed in paragraph (a);

(B) Upon receipt of such exemption, shall negotiate with, and obtain proposals with regard to placement of such securities from, at least three prospective dealers, purchasers or underwriters, each of whom shall be notified of the prohibitions set forth in paragraph (c);

(C) File an application for authority to issue such securities, pursuant to § 34.3.

(ii) Upon the Commission's authorization to a utility to issue such securities, such utility may, without further Commission action, make such issuances.

(c) *Prohibitions respecting competitive bids or negotiated placements.* No bid for the placement of any securities shall be invited or accepted from, nor shall negotiations occur with, any person who:

(1) Prior to the submission of bids, or beginning of negotiations, has performed any service for any fee or compensation in connection with such proposed issuance of securities; or

(2) Violates section 305(a) of the Federal Power Act with respect to such bid, invitation, or negotiation.

§ 34.3 Contents of application for competitive bids or negotiated placements.

Each application to the Commission for authority to issue securities shall contain the following information:

(a) The exact name of the applicant and address of its principal business office.

(b) The State or other sovereign power under which the utility is incorporated, the date of incorporation, and each State in which it operates.

(c) The name, address and telephone number of the person within the utility authorized to receive notices and communications with respect to the application.

(d) The date by which Commission action is requested.

(e) A full description of the securities proposed to be issued, including:

(1) Type and nature of securities;

(2) Amount of securities (par or stated value and number of units);

(3) Interest or dividend rate, if any;

(4) Dates of issuance and maturity;

(5) Institutional rating of the securities, or if the securities are not rated, an explanation thereof;

(6) Any stock exchange on which the securities will be listed; and

(7) If such issuance is exempt from the competitive bidding requirements pursuant to § 34.2(a)(1) (i), (ii) or (iii), information in support of such exemption shall be filed.

(f) A description of the method used for issuance and sale of the proposed securities or the procedure by which the applicant will assume any obligation or liability as guarantor, endorser, surety, or otherwise.

(g)(1) (i) The name and address of any person receiving or entitled to receive a fee for services (other than attorneys, accountants and similar persons who render technical services) related to the negotiation, issuance or sale of securities; or, receiving or entitled to receive a fee for services in securing underwriters, sellers, or purchasers of securities, except as related to any competitive bid;

(ii) The amount of each such fee;

(iii) The facts showing that the services are necessary, and that the fee is reasonable for rendering services in an arm's length transaction; and

(iv) Any other relevant factors.

(2) All facts showing or tending to show that the applicant directly or indirectly controls, is controlled by, or is under the same common control as any person named pursuant to the requirements of paragraph (g)(1)(i); or facts showing or tending to show the contrary. For purposes of this clause, "control" has the same meaning as "Control" in Item 5.B. of the Definitions at 18 CFR Part 101 Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (Class A and Class B).

(h) The purpose for which securities are to be issued:

(1) If the purpose for such issuance is the construction, completion, extension, or improvement of facilities, describe in reasonable detail the construction program for which the funds were or are to be used and submit such information as part of Exhibit I.

(2) If the purpose for such issuance is for the refunding of obligations, describe in detail the obligations to be refunded, including the character, principal amounts, applicable discount or premium, dates of issuance and maturity, and all other material facts concerning such obligations.

(3) If the purpose for such issuance is for other than construction or refunding, explain such other purpose(s) in detail.

(i) A statement as to whether or not any application with respect to the transaction or any part thereof is required to be filed with any State regulatory body.

(j) A detailed statement of the facts relied upon by the applicant to show that the issuance:

(1) Is for some lawful object, within the corporate purposes of the applicant and compatible with the public interest, is necessary or appropriate for or consistent with the proper performances by the applicant of service as a public utility and will not impair its ability to perform that service, and

(2) Is reasonably necessary or appropriate for such purposes.

(k) A detailed statement of the bond indenture(s) or other limitations on interest and dividend coverage, and the effects of such limitations on the issuance of additional debt or equity securities.

(l) A brief summary of any rate changes which were made effective during the period for which financial statements are submitted or which became or will become effective after the period for which statements are submitted.

(m) A form of notice suitable for publication in the **Federal Register**, setting forth: (1) the legal name of the applicant, (2) the securities offered for issuance including the proposed issue date, (3) the purpose of the issuance, and (4) the comment procedure.

(n) Each of the applicable exhibits required under § 34.4.

§ 34.4 Required exhibits.

(a) *Exhibit A.* A copy of the applicant's charter or articles of incorporation with amendments to date; and a copy of the by-laws with amendments to date: *Provided, however,* That if the documents required in this exhibit have been filed with the Commission no more than 5 years prior to the current application, a specific reference to and the date of such previous filings will be accepted in lieu of separate filings; but if such documents have been filed more than 5 years prior to the current application, a copy of the most recent articles of incorporation and bylaws with all amendments to date shall be filed.

(b) *Exhibit B.* A copy of all resolutions of applicant's directors authorizing the issuance of securities for which the application is made; and copies of the resolution of the stockholders approving such issuance if approval of the stockholders has been obtained.

(c) *Exhibit C.* A statement of the measure of control or ownership exercised by or over the applicant as to

any utility, bank, trust company, banking association, firm that is authorized by law to underwrite or participate in the marketing of securities of a utility, or any company supplying electric equipment to such applicant. If any intercorporate relationships exist among any such entities through holding companies, ownership of securities, or otherwise, a statement is required concerning the ownership of securities or the nature and extent of such relationship. If the applicant is not a member of any holding company system, a statement to that effect is required.

(d) *Exhibit D.* Balance sheets and supporting plant schedules with attached notes for the most recent 12 month period, on both an actual basis and pro forma basis in the form prescribed for Statement A, "Comparative Balance Sheet," and Statement B, "Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion," of Form No. 1, "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)" (*see* 18 CFR 141.1). Each adjustment made in determining the pro forma basis shall be clearly identified.

(e) *Exhibit E.* Income statement, with attached notes, for the most recent 12 month period, on both an actual basis and a pro forma basis in the form prescribed for Statement C ("Statement of Income for the Year") of Form No. 1. Each adjustment made in determining the pro forma basis shall be clearly identified.

(f) *Exhibit F.* A copy of registration statement and exhibits which are filed with the Securities and Exchange Commission for the proposed security issuance.

(g) *Exhibit G.* A copy of the public invitation(s) for proposals to purchase or underwrite the securities offered for issuance.

(h) *Exhibit H.* (1) A copy of each proposal received by the applicant for a negotiated placement of the securities offered for issuance, and a summary tabulation of all proposals. The summary shall include the following information, identified by prospective dealer, purchaser or underwriter:

(i) Par or stated value of the securities.

(ii) Number of units (shares of stock, number of bonds) to be issued.

(iii) Total dollar amount of the issue.

(iv) Life of the securities, including maximum life and average life, for a sinking fund issue.

(v) Dividend or interest rate.

(vi) Call provisions.

(vii) Sinking fund provisions.

(viii) Offering price to public or to other purchaser(s).

(ix) Discount or premium.

(x) Commission or underwriting spread.

(xi) Net proceeds to company for each unit of security and for the total issue.

(xii) Net cost to the company for securities with a stated interest or dividend rate.

(xiii) Other pertinent data.

(2) A list identifying any person with whom negotiations took place but from whom no proposal was received.

(3) A justification in support of the utility's intention to accept a particular offer.

(i) *Exhibit I.* Information concerning the construction program including:

(1) The name, location and size (in megawatts) of generating stations which are to be constructed, or in which are to be installed major additions such as generators, boilers, etc.;

(2) The length of transmission lines to be constructed or rebuilt, the geographical termini of such lines, the supporting structure, number of circuits, size and type of conductor, the voltage, frequency, and number of phases;

(3) Name and location of major substations to be constructed or rebuilt, the kilovolt capacity and voltages of transformers installed;

(4) Any other major additions or improvements to electric facilities;

(5) The expenditures (to most recent date), the estimated completion date, the ultimate cost in place for each of the items listed in items A through D. If the construction program extends over more than one calendar year, provide the

estimated cost for each succeeding calendar year; and

(6) Any deletions of significant items such as a generating station or major transmission line, or any significant changes in the total estimated cost for such facility which were previously submitted in an application under this Part: *Provided, however,* That if the information required in this exhibit is reported in the Commission's Form No. 1 or other Commission report, a specific reference to the appropriate portions of such report may be attached in lieu of filing this exhibit.

(j) *Exhibit J.* A tabulation showing, for each of the next five years, the applicant's estimate in megawatts of its peak load, and the generating capacity (*i.e.*, system plus purchases, minus sales) which will be available to meet such loads. Explain briefly in a footnote any plans to dispose of any excess capacity or to provide for deficient capacity: *Provided, however,* That if the information required in this exhibit is reported in a Commission report or ERA Form No. 119–A, a specific reference to the appropriate portions of such report may be attached in lieu of filing this exhibit.

(Federal Power Act, Secs. 3, 4, 15, 16, 301, 308, 309; 41 Stat. 1063–1066, 1068, 1072, 1075; 49 Stat. 838, 839, 840, 841, 854–856, 858–859, 82 Stat. 617 (U.S.C. 796, 797, 803, 808, 809, 816, 825, 825b, 825c, 825g, 825h, 826i))

§ 34.5 Additional information.

The Commission may, in its discretion, require the filing of additional information which appears necessary to reach a determination on any particular application.

§ 34.6 Form and style.

Each application pursuant to Part 34 shall conform to the requirements of § 1.15 of this chapter.

§ 34.7 Number of copies to be filed.

Each applicant shall submit to this Commission an original and five copies of each application pursuant to Part 34.

§ 34.8 Verification.

The original application shall be signed by an authorized representative of the applicant, who has knowledge of the matters set forth therein, and it shall be verified under oath.

§ 34.9 Filing fee.

Each application shall be accompanied by a fee as prescribed in 18 CFR 36.2.

§ 34.10 Reports.

The applicant shall file a report pursuant to 18 CFR 131.43 no later than 45 days after the sale or placement of equity or long-term debt securities, or entry into other contractual obligations pursuant to authority granted under this Part. This requirement does not apply to debt having a maturity of one year or less.

PART 131—FORMS

2. Section 131.43 is amended by revising the first two parenthetical sentences following the section heading, to read as follows:

§ 131.43 Report of securities issued.

(See § 34.10 of this chapter.)

(Submit an original and five copies.)

* * * * *

3. Section 131.50 is revised to read as follows:

§ 131.50 Certificate of notification.

(See § 34.1(c)(2) of this chapter. If the aggregate amount of the issuance reported herein, together with all other outstanding notes and drafts with a maturity of 1 year or less is in excess of 5 percent of the par value of the outstanding securities at the date of the issuance in accordance with § 34.1(c)(2)(B) of this chapter, the respondent shall file an application pursuant to Part 34 of this chapter.)

(Submit an original and five copies.)

[Name of public utility]

[Address of public utility]

This is to certify that the following are the facts relating to an issuance entered into by the above-named public utility to which the provisions of section 204(e) of the Federal Power Act are applicable:

(1) Date of issuance, renewal, or assumption.

(2) Description of the terms of the note or draft including the amount, payee, interest rate and maturity date.

(3) Aggregate amount of such note or draft, and all other outstanding notes and drafts of a maturity of 1 year or less on which the public utility is primarily or secondarily liable at the date of this issuance.

(4) Total par value (or, in the case of securities having no par value, the fair market value as of the date of this issuance) of all other securities outstanding at the date of this issuance.

(5) Full details on how fair market value of securities having no par value was calculated at the date of this issuance of securities.

(6) Date of State authorization and docket number, if applicable.

_____

(Name and title of person who signs this certificate)

[CORPORATE SEAL]

Subscribed and sworn to before me this —— day of ————, 19——.

_____

(Notary public)

Only original need be verified.

¶ 32,117 Interstate Pipeline Blanket Certificates for Routine Transactions

46 F. R. 16903 (March 16, 1981)

18 CFR Parts 157 and 375

[Docket No. RM81-19]

Interstate Pipeline Blanket Certificates for Routine Transactions; Proposed Rulemaking

March 10, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it proposes to adopt regulations providing procedures for the issuance of blanket certificates of public convenience and necessity under section 7(c) of the Natural Gas Act. The blanket certificates will authorize interstate pipelines to perform various specified activities, including construction of facilities and transportation and storage of natural gas. The proposed rule would create an integrated program for authorizing interstate pipeline activities, resulting in a reduction of regulatory burdens.

DATES: Requests for oral hearing by April 27, 1981. Public hearing on May 4, 1981. Written comments by May 8, 1981.

ADDRESS: All comments and requests for oral hearing to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Robert C. Platt, Assistant Advisory Counsel, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8457;

or

Robert J. Cupina, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-9036.

SUPPLEMENTARY INFORMATION:

I. Background

The Federal Energy Regulatory Commission (Commission) is proposing a rule to modify its procedures under the Natural Gas Act for issuing certificates of public convenience and necessity to interstate pipelines. The modifications would create an integrated program under which some transactions would be authorized under a "blanket certificate" covering various defined generic actions of interstate pipelines, other transactions would be authorized under the blanket certificate only after a notice and protest procedure has been completed, while certificates for still other types of pipeline activities would continue to be issued as a result of case-specific determinations by the Commission.

Section 7 of the Natural Gas Act, 15 U.S.C. 717f, provides that no natural gas company may engage in the transportation and sale of natural gas in interstate commerce for resale, the construction of facilities to be used in those activities, or the abandonment of any jurisdictional service or facilities, prior to obtaining the Commission's approval of such activities. To carry out this statutory responsibility, the Commission has a number of different certificate programs. Some of these programs involve various generic determinations of public convenience and necessity and the issuance of so-called blanket certificates or "budget-type certificates" which permit interstate pipelines to undertake specific activities which fall within parameters established generically. Actions covered by section 7 which do not fall

within some blanket certificate program are authorized by certificates granted on a case-by-case basis.

In an effort to make the certificate process more efficient, the Commission has delegated a number of its activities to the Director of the Office of Producer and Pipeline Regulation (18 CFR 375.307). Each delegated activity requires significant time and effort by the pipeline companies and Commission staff. The Commission has also provided (18 CFR 1.32 and 157.11) for expedited hearings by the full Commission of uncontested, routine applications. In addition, § 157.7(a) provides for short-form applications where special information is not required or already has been filed with the Commission. Despite these efforts to expedite the process of considering and disposing of applications for certificates of public convenience and necessity, the Commission is of the opinion that substantial opportunities for regulatory reform remain.

One suggestion for regulatory reform of the Commission's certificate and abandonment authorization procedures was made by the Subcommittee on Regulatory Process of the Commission's Advisory Committee on Practice and Procedure. The Subcommittee strongly endorsed a new-notice and comment procedure for many of the certificates currently issued by the Commission after a case-specific determination. One of the purposes of this rulemaking is to implement that suggestion by the Commission's Subcommittee.[1]

Another purpose of this rulemaking is to provide an opportunity for a general review of the Commission's procedures for granting certificates of public convenience and necessity. Where it appears appropriate, the Commission is prepared to change the specifications and qualifications for blanket certificates. The Commission is also prepared to adjust its delegation assignments as appropriate. And, as noted, the Commission proposes to issue blanket certificates which would create a new notice and comment procedure for certain actions by jurisdictional pipelines that require certification. The Commission hopes that the end result of this rulemaking will be more streamlined and efficient procedures and specifications that reflect current economic conditions and the experience of the Commission in granting certificates. In addition, the Commission believes the proposed changes will lead to a more integrated and coherent program for granting certificates.

The Commission has divided the various actions that it certificates into three categories. The first category is routine actions by interstate pipelines that either have relatively little financial impact on the ratepayer or are routine pipeline operations and investments which are so well understood as an established industry practice that relatively little scrutiny is required to determine their compatibility with the public convenience and necessity. The second category is comprised of relatively routine actions in which various interested parties might or might not have a concern. In such cases there is a need to provide an opportunity for a closer review and possible adjudication of controversial aspects. The third category is comprised of actions with such a major potential impact on the ratepayer or which propose such non-routine and important considerations that close scrutiny and case specific deliberation by the Commission is warranted prior to the issuance of a certificate.

For the first category the Commission proposes to utilize a blanket certificate program similar to that provided in Subpart G of Part 284. For the second category the Commission proposes to

[1] While the proposed rule would not implement the suggestions of the subcommittee in their entirety, the blanket certificate procedure would implement most of the suggestions, and where variations are proposed, the Commission contemplates that the public interest would be better served by assuring that essential information is available at the time of filing so that unnecessary protective interventions or protests can be avoided.

utilize a notice and comment procedure similar to the Advisory Committee's proposal. For the third category the Commission proposes to continue to utilize its existing case-specific deliberation procedures as provided in the present regulations at Part 157. The Commission invites comments both upon the procedures proposed for each category and upon the classification of particular transactions into the categories.

Not all possible transactions have been addressed in this proposed rule. The areas that may be addressed in future rule makings include: (1) sales for resale between interstate pipelines, (2) modification of restrictions placed on transportation arrangements for gas sold to end-users, (3) section 311(a)(2) authorization of intrastate pipeline transportation incidental to any transaction authorized under the blanket certificate, and (4) modification of the Commission's regulations implementing sections 311 and 312 of the NGPA.

II. Summary of the Proposed Rule

Under the proposed rule, any interstate pipeline proposing to undertake certain defined categories of routine investment or operations may obtain a one-time blanket certificate of public convenience and necessity that will authorize such transactions (which are described in §§ 157.208 through 157.218).

Subject to the conditions imposed by the blanket certificate, the holder is automatically authorized to engage in the first category of transactions, without making formal application to the Commission. The certificate holder will be required to file annual reports summarizing the transactions which have been authorized under the certificate.

For actions which fall in the second category, the interstate pipeline will file a request with the Commission. The required contents of each request is significantly less than the required elements of a certificate application filed under the Commission's existing regulations. Notice of this request will be published in the **Federal Register**. If neither the Commission staff nor any other interested party files a protest within the specified 45-day period, the transaction is authorized under the blanket certificate.[2] If a protest is filed, the action is not authorized under the blanket certificate and must be considered in accordance with the procedures required for the third category of arrangements.

The third category of arrangements are authorized through case-specific deliberation by the Commission. As noted, the Commission would propose to utilize its present procedures for certificate proposals that fall in this category.

Section 157.206 of the proposed rule specifies the standard conditions which will pertain to any blanket certificate issued under this subpart. The intent of these conditions is to reflect the standard Commission practice regarding such policy issues as the treatment of production-related costs and allocation of costs to the transportation of liquids and liquefiable hydrocarbons. On other important matters, such as environmental considerations and disposition of revenues, a uniform set of criteria will be imposed in order to reconcile the Commission's case-specific statutory obligations with the scope of the generic authorization embodied in the blanket certificate.

One of the issues considered by the Commission in preparing this proposed rule was what procedures are appropriate in a case where facts are called to the Commission's attention which indicate that a request contained an untrue statement of material fact or

[2] Temporary certificates would also continue to be available to interstate pipelines requiring immediate authorizations in emergency situations. In cases where a pipeline cannot wait for the 45-day notice period, the pipeline may file a case-specific application accompanied by a request for a temporary certificate.

omitted a statement of material fact which renders the request misleading. If such untrue statements or omitted facts occur in the environmental portions of a request, prompt Commission action may be necessary in order to prevent environmental damage. The Commission believes that its existing enforcement authority is sufficient to handle any such instance. However, the Commission invites public comment upon whether a specific termination procedure should be added as a standard certificate condition.

III. Authorized Transactions

The division of the Commission's certificate caseload into the three categories discussed above is summarized in the following table:

Category	Self-implementing procedure	Prior notice procedure	Case by case review procedure
Construction and then operation of facilities	Projects costing less than $3.5 million [1]	Projects costing between $3.5 and $10 million	Projects costing more $10 million.
End user transportation	Up to 5 yr if eligible under order No. 2 or 27, and other programs authorized in the future.	Greater than 5 yr	Transportation to end-users outside the "Qualified end-user definition."
Transportation of system supplies	None (see order No. 60)	If on behalf of an interstate pipeline, intrastate pipeline or distribution.	None.
Sales for resale	(To be cored by separate rulemaking)		
Sales taps	Right of way grantor, subject to a 200 million Btu per day limit.	Other sales taps, if within certificate entitlements.	None.
Change in delivery points	None	If change is between rate zones	None.
Contract storage service	Up to 2 yr under commission approved rate schedule.	In excess of 2 yr	If no commission approved rate schedule on file.
Change in storage capacity	None	If no new facilities are required	If new facilities are required.
Abandonments	Gas supply facilities if producer abandonment obtained or unnecessary.	Sales tape or lateral lines, if all customers consent.	If customers do not consent or producer certificate is outstanding.
Change in rate schedules	Volumetric limits not increased	None	If volumetric limits increased.
Name change	Customer's name, if the result of reorganization or acquisition.	None	None.

[1] Subject to an annual limit which varies between $1 million and $36 million depending upon the size of the pipeline. These limits escalate with the implicit GNP deflator.

A. Construction, Acquisition and Operation of Facilities

At present, various types of minor transactions, most of them involving the construction and operation of facilities are authorized under the "budget-type" certificate program set forth in § 157.7, paragraphs (b) through (g). The regulations authorize four kinds of transactions so long as the cost of constructing the facilities for each transaction does not exceed certain monetary limits. The four types of transactions presently authorized include: construction of facilities for attaching gas supplies, testing and development of underground storage, abandonment of direct sales measuring stations, and miscellaneous facility rearrangements. Under present regulations, a separate "budget-type" certificate must be obtained for each category of construction or abandonment. In addition, in three of the categories, certificate applications must be refiled each year.

The proposed procedure presents advantages over the budget-type certificate program because it simplifies the certification process and authorizes the construction of a greater range of facilities. Under the proposal only one certificate would be required to authorize the construction and operation of any minor facility so long as the certificate holder does not exceed certain cost limitations. A "minor facility" is any jurisdictional facility in the gas transmission system except for the main line, an extension of the main line, or a facility which alters the capacity of a main line.

If the cost of the facility does not exceed $3,500,000, the construction and operation of the facility is automatically authorized. The authorization to automatically construct facilities is also subject to an annual limit which is the lesser of $36,000,000 or 3% of the certificate holder's net plant. A company with less than $33.3 million in its net gas plant account may construct facilities having a total annual cost of up to $1,000,000. However, upon application this annual limit may be waived. Facilities which exceed $3,500,000 but not $10,000,000 may be authorized under the blanket certificate but are subject to the notice procedure. (The $3,500,000, $10,000,000 and $36,000,000 limits will be adjusted annually to reflect inflation.) For any year in which minor facilities are constructed under the authority of the blanket certificate, the certificate holder must file an annual report concerning the facilities constructed.

Because the proposed blanket certificate authorizes the construction and operation of everything that could be authorized under a budget-type certificate and reduces the procedural burdens imposed during the certificate process, the Commission proposes to eliminate the budget-type certificate program when the blanket procedure becomes effective. The terms and conditions of any outstanding budget-type certificate would remain effective. However, upon adoption of a final rule in this docket, the Commission would no longer accept applications for budget-type certificates. Moreover, each blanket certificate holder would be required to surrender any outstanding budget-year certificate as a condition of accepting a blanket certificate.

B. Transportation

The proposed rule authorizes transportation services for both the system supply of other pipelines and distributors as well as for certain individual end-users.

1. *End-user transportation.*—The Commission has a number of separate end-user transportation programs under Order Nos. 2, 27 and 30, for different categories of end-users. Section 2.79, promulgated by Order No. 2, permits interstate pipelines to transport gas sold by producers to certain commercial, process and feedstock users. Subpart E of Part 157, promulgated by Order No. 27, permits interstate pipelines to transport gas to schools, hospitals, and essential agricultural users. Subpart F of

Part 284, promulgated by Order No. 30, authorizes the transportation of fuel oil displacement gas. The eligibility criteria and certificate conditions are different for each program. Except for certain Order No. 30 transaction,[3] the regulations under each program require separate certification for each transaction. Under the proposed rule, any end-user who is eligible to participate in the Order Nos. 2, 27 and 30 programs would be able to obtain pipeline transportation of the end-user's natural gas under the blanket certificate. The blanket certificate would eliminate the need for separate certification of each transaction. Transportation of end-user owned gas for periods greater than five years duration would be subject to the notice procedure. Regardless of whether authorized automatically or after the notice procedure, all transportation arrangements for end-users would be subject to the current eligibility criteria and end-use restrictions of Order Nos. 2, and 27 or such other programs as may be prospectively designated.[4]

2. *Transportation for system supplies.*—The current blanket certificate program promulgated by Order No. 60 and contained in Subpart G of Part 284 authorizes the transportation of natural gas by an interstate pipeline on behalf of any other interstate pipeline. At Subpart B of Part 284 certain transportation of gas by any interstate pipeline on behalf of any intrastate pipeline or any local distribution company is authorized under section 311(a)(1) of the NGPA. Both of these authorizations are limited to transactions involving two years or less. The Commission intends to retain both the Order No. 60 blanket certificate program and the self-implementing transportation authorizations under section 311(a). However, the proposed rule would give a holder of a blanket certificate the additional option (after following the notice procedure) of entering into certain transportation arrangements which will extend beyond two years. Such transportation may not require additional capacity and the gas transported must ultimately become a part of the system supply of a pipeline or distributor.

C. Sales for Resale

The Commission will consider in a separate rulemaking whether or not sales for resale between interstate pipelines for system supplies should be authorized under the blanket certificate program proposed under this rulemaking. At this time the Commission simply proposes to reserve a section for sales for resale between interstate pipelines.

D. Sales taps

1. *Right-of-way grantors.* The present policy of the Commission is to routinely approve, through normal certification procedures, the construction and operation of sales taps[5] for the delivery of relatively small volumes of gas to right-of-way grantors if the tap is permitted as consideration for a right-of-way easement obtained by the certificate holder.[6] The proposed blanket certificate would authorize automatically such sales taps so long as the gas at each tap to be delivered does not exceed 200 MMBtu per day.

2. *Existing customers.* Under existing regulations, an interstate pipeline must also obtain a certificate for each sales tap it constructs to serve other customers as well as right-of-way grantors. The Commission reviews both the end-use of the gas and the proposed sales price before authorizing the construction of a tap. If the end-use and

[3] Order No. 30, in § 284.202 does authorize certain transportation on a generic basis under section 311(a)(1) of the NGPA.

[4] The Order No. 30 program automatically expires on May 31, 1981.

[5] A sales tap consists of the incidental facilities necessary to serve a new customer from the certificate holder's existing line. It includes meters and connecting pipe.

[6] Opinion No. 773, issued August 13, 1976, in Docket No. CP75-333.

price are appropriate, taps for existing customers are routinely approved. Under the proposed rules, construction of new taps to connect existing customers of the certificate holder are authorized subject to the notice procedure.

E. Changes in Delivery Points

At present, the Commission gives case-by-case consideration to applications for certificate amendments authorizing new delivery points or reassignment of delivery points. These amendments are routinely authorized. Proposed § 157.212 authorizes (subject to the notice procedure) a certificate holder to add new delivery points or reassign volumes between delivery points. The total volumes to be delivered to the customer may not exceed the volumes previously authorized. The change is not authorized if it is prohibited by the certificate holder's tariff or if the certificate holder does not have sufficient capacity to accomplish the deliveries without detriment or disadvantage to other customers.

F. Performance of Storage Service

The Commission routinely authorizes pipelines to provide storage service where such service does not exceed the pipeline's existing capacity. However, under the present regulations such authorization must be obtained through normal certification procedures each time the pipeline proposes to provide such service. Proposed § 157.213 provides blanket authorization for the certificate holder to provide storage service if the storage service is within the certified storage capacity of the certificate holder, the term of the service does not exceed two years and, the rate for the service is covered by an effective rate schedule. Any such storage arrangement which exceeds two years may be authorized but is subject to the notice procedure.

G. Increase in Storage Volumes

Proposed § 157.214 authorizes the certificate holder to provide for the storage of additional volumes of natural gas so long as the certificate authorized the operation of a storage field, and the additional storage will not exceed the physical limitation of the facility and will not require the construction of additional facilities. Such authorization is subject to the notice procedure. Most problems which arise with respect to the storage of additional volumes in an existing facility concern the safety of providing such additional storage. Therefore, in requesting authorization for additional storage the certificate holder must submit information which reflects the facility's ability to store additional volumes. In addition the certificate holder must submit a semi-annual report containing information pertinent to the safety of the storage facilities.

H. Underground Storage Testing

Section 157.7(d) of the Commission's existing budget-type certificate regulations authorize a testing and development of underground storage fields for a term of three years. The authorization provided in § 157.7(d) are carried forward in § 157.215. Because of the perpetual term of the blanket certificates, the three year time limit and $3,000,000 limit contained in § 157.7(d) have been dropped. Under proposed § 157.215, the certificate holder may test and develop any number of proposed storage fields, so long as no more than $1,000,000 is spent on such testing during any given year.

I. Abandoment

The Commission routinely authorizes pipelines to abandon gas supply facilities where the sales have already terminated and any necessary abandonment was obtained. Again, these transactions must presently be authorized on a case-by-case basis pursuant to the normal abandonment procedure. Proposed § 157.216 authorizes abandonment of gas supply facilities and service if the seller has been authorized to abandon the sale or the sale has ceased and has been removed from the Commission's abandonment jurisdiction by operation

of section 601(a)(1) of the NGPA. The authority to abandon these facilities is automatic under the blanket authorization. Sales taps or lateral and related facilities may be abandoned subject to the notice procedure if all buyers currently served through the tap or lateral line consent to the abandonment. Buyers currently served do not include customers which have ceased to exist.

J. Changes in Rate Schedules

The Commission has routinely amended certificates to permit an existing customer to change from one rate schedule to another. Proposed § 157.217 automatically authorizes the certificate holder to shift purchases of an existing customer from one rate schedule to another. Such changes are authorized if they have the effect of not changing the total volumetric limitations on deliveries for that customer and must be consistent with the terms of effective tariffs.

K. Changes in Customer

Finally, the Commission also routinely approves amendments to outstanding certificates to reflect customer name changes. Proposed § 157.218 automatically authorizes amendments in outstanding certificates to reflect the change in the name of an existing customer if the name change is a result of corporate reorganization or acquisition. Where the customer's name changes for other reasons the authorization of the amendment is subject to the notice procedure. Because the Secretary of the Commission is already authorized to change the name of a certificate holder under § 375.302(a), no corresponding authority is needed under the blanket certificate.

IV. Environmental Issues

An environmental assessment of the proposed rulemaking is being prepared by the Commission's environmental staff. This assessment will identify the significance of any potential environmental impact which might result from transactions which would be authorized under the blanket certificate. The environmental assessment will provide the basis for determining the need to prepare an environmental impact statement (EIS) prior to the issuance of the final rule.

Full consideration will be given to the type of projects and actions allowed under the self-implementing and notice procedure authorizations and to the proposed standard environmental compliance conditions and environmental reporting requirements proposed in the rulemaking. The assessment will evaluate direct environmental effects that may occur from authorizing transactions such as construction of facilities proposed in §§ 157.208 and 157.211 as well as secondary effects that might arise from non-construction transactions authorized in §§ 157.209, and 157.212 through 157.218.

Any person who wishes to submit comments on environmental issues should provide a detailed explanation which address each specific environmental concern and the reason each concern is felt to be a significant issue. This information will be helpful to the staff in developing an environmental record in this rulemaking, and will be incorporated in the Commission's scoping process should an EIS be prepared.

V. Certification of No Significant Economic Impact on Small Businesses

The Regulatory Flexibility Act (RFA)[7] requires certain statements, descriptions and analyses of proposed rules that will have "a significant economic impact of a substantial number of small entities."

Pursuant to section 605(a) of the RFA, the Commission finds that the provisions of the Act do not apply to this rulemaking. If promulgated, this rulemaking would simplify the

[7] 5 U.S.C. 601–602 (Pub. L. 96–345, September 19, 1980).

procedures under which interstate pipelines may obtain certificates authorizing routine transactions. The budget-type certificate regulations were promulgated for similar purposes 24 years ago. The characteristics of the participants in the budget-type certificate program reflect the nature of the interstate pipeline industry. With five exceptions, only Class A pipeline companies* have participated in the program. Of the five exceptions, only two were not affiliated with a major natural gas company. Because the nature of the budget-type certificate program and the proposed blanket certificate program are similar, the nature of the participants in each program should also be similar. Therefore, the Commission believes that very few, if any, of the interstate pipelines which will participate in this program will be small entities.

As such, this rulemaking does not impose any regulatory or administrative burdens upon a significant number of small entities, nor does it require an expense of resources by such entities. For these reasons, the Commission hereby certifies that this rulemaking, if promulgated, would not have a significant impact on a substantial number of small entities.

VI. Public Comment Procedure

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM81-19. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, May 8, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. during regular business hours.

B. Public Hearing

A public hearing on this proposed rule will be held on May 4, 1981, beginning at 10:00 a.m. EST at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing. Interested persons may also obtain this information by calling the Office of the Secretary of the Commission.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than seven days prior to the hearing. Requests should reference Docket No. RM81-19, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Division of Public Information three days before the hearing and will be available at the site of the hearing on the morning it is convened.

The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officers to be asked of persons making statements. The presiding officer will determine whether

*To be classified as Class A company, the company's should have annual gas operating revenues of $2,500,000 or more and maintain that level for three consecutive years. (See Part 201, Uniform System of Accounts for Natural Gas Companies Subject to the Provisions of the Natural Gas Act (Class A and Class B); General Instructions.

the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available in the public file for this proceeding, Docket No. RM81-19 in the Commission's Division of Public Information.

(Natural Gas Act, 15 U.S.C. 717; Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. 3301])

Accordingly, the Commission proposes to amend the regulation in Part 157, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By Direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 157—[AMENDED]

1. Part 157 is amended in the Table of Contents by adding Subpart F to read as follows:

Subpart F—Interstate Pipeline Blanket Certificate and Abandonment Authorization Under Section 7 of the Natural Gas Act for Routine Transactions

Sec.

157.201 Applicability.
157.202 Definitions.
157.203 Blanket certification.
157.204 Application procedures.
157.205 Notice procedure.
157.206 Standard conditions.
157.207 General reporting requirements.
157.208 Construction and operation of facilities.
157.209 Transportation.
157.210 Sales for resale [Reserved].
157.211 Construction and operation of sales taps.
157.212 Changes in delivery points.
157.213 Storage services.
157.214 Increase in storage capacity.
157.215 Underground storage testing and development.
157.216 Abandonments.
157.217 Changes in rate schedules.
157.218 Changes in customer name.

Authority: Natural Gas Act, 15 U.S.C. 717, Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. 3301.

2. Part 157 is amended by adding a new Subpart F to read as follows:

Subpart F—Interstate Pipeline Blanket Certificate and Abandonment Authorization Under Section 7 of the Natural Gas Act for Routine Transactions

§ 157.201 Applicability.

(a) *Scope.* This subpart establishes a procedure whereby any interstate pipeline may obtain a blanket certificate authorizing certain routine construction and operation of facilities, transportation, and sales arrangements under section 7 of the Natural Gas Act. Each blanket certificate also authorizes certain routine certificate amendments and abandonments.

(b) *Who may apply.* This procedure is only applicable to interstate pipelines.

(c) *Cross-references.* For other blanket certificate authorizations applicable to interstate pipelines and certain local distribution companies, see Subpart G of Part 284 of this chapter.

(d) *Availability of case-specific certificates.* Nothing in this subpart shall preclude an interstate pipeline from proceeding under any other provision of the Commission's regulations to obtain Commission approval of abandonments or a temporary or permanent certificate of public convenience and necessity or from proceeding under section 311(a)(1) of the NGPA regarding transportation service if applicable.

§ 157.202 Definitions.

For the purposes of this subpart:

(a) Terms defined in the Natural Gas Policy Act of 1978 shall have the same meaning for the purposes of this subpart as they have under the NGPA.

(b) "Certificate holder" means any interstate pipeline with an effective blanket certificate issued pursuant to this subpart.

(c) "Gas supply facilities" means minor, routine facilities subject to the Natural Gas Act jurisdiction of this Commission, which are necessary to connect the system of an interstate pipeline company, or the system of another pipeline company authorized to transport gas for or exchange gas with an interstate pipeline company to

natural gas supplies destined for the system supply of an interstate pipeline company.

(d) "Main line" means the principal transmission facilities of a pipeline system to market areas and does not include small diameter lateral or gathering lines.

(e) "Minor facility" means any facility except a main line of a transmission system, or an extension of a main line; a facility, including compression, which alters the transmission capacity of a main line system; or facilities required to develop an underground storage field or to store gas above ground in either a gaseous or liquid state. "Facility" shall not be interpreted to include any item described in § 2.55 of this chapter.

(f) "NGPA" means the Natural Gas Policy Act of 1978.

(g) "Project" means a unit of improvement or construction which upon completion is functional without any further construction of facilities.

(h) "Project cost" means the total actual cost of constructing a project. In the case of a project constructed jointly by more than one interstate pipeline, the project cost is the total cost, irrespective of the amount paid by each pipeline.

(i) "Right-of-Way grantor" means a person who grants a right of way easement to the certificate holder in reliance upon obtaining natural gas service as part of the easement agreement.

(j) "Sales tap" means metering and appurtenant facilities necessary to enable the certificate holder to deliver gas to a distribution customer or an end-user.

(k) "Sensitive environmental area" means:

(1) The habitat of a species which has been identified as endangered or threatened species under the Endangered Species Act (Pub. L. 93–205, as amended),

(2) National or State Forests or Parks,

(3) Sites listed in, or eligible for inclusion in, the National Register of Historic Places, or the National Register of Natural Landmarks,

(4) Flood plains and wetlands,

(5) Designated or proposed wilderness areas or national or state wild and scenic rivers, wildlife refuges, or preserves, or

(6) Prime agricultural lands, designated by the Department of Agriculture.

(l) "Qualified end-user" means:

(1) An "eligible user" as defined in § 157.102(b) of this chapter;

(2) Any end-user eligible to receive gas transported under § 2.79 of this chapter; or

(3) Any end-user which the Commission specifically authorizes from time-to-time to receive gas under this subpart.

(m) "Storage service" means the receipt of natural gas for injection into storage and the subsequent withdrawal of an equivalent volume (less any fuel or unaccounted for volumes) at a later date.

§ 157.203 Blanket certification.

(a) *Effect.* A blanket certificate issued pursuant to this subpart authorizes an interstate pipeline to engage in any of the activities specified in § 157.208 through § 157.218 (as amended from time to time) in accordance with the provisions of this subpart.

(b) *Automatic authorization.* A blanket certificate issued pursuant to this subpart authorizes the certificate holder to engage in transactions described in §§ 157.208(a), 157.209(a), 157.211(a), 157.213(a), 157.215, 157.216(a), 157.217 and 157.218(a) without further Commission approval.

(c) *Prior notice required.* A blanket certificate issued pursuant to this subpart authorizes the certificate holder to engage in transactions described in §§ 157.208(b), 157.209(b), 157.211(b), 157.212, 157.213(b), 157.214, or 157.216(b), if the requirements of § 157.205 have been fulfilled and no protests were filed in accordance with § 157.205(d).

§ 157.204 Application procedure.

(a) *Who may apply.* Any interstate pipeline may apply for a blanket certificate under this subpart.

(b) *Hearing procedure.* Upon receiving an application for a blanket certificate under this subpart, the Commission will conduct a hearing pursuant to section 7(c) of the Natural Gas Act and §§ 1.32 and 157.11 of this chapter.

(c) *Issuance.* If required by the present or future public convenience and necessity, the Commission will issue a blanket certificate to the applicant.

(d) *Application contents.* Applications for blanket certificates shall contain:

(1) Information indicating the exact legal name of applicant; its principal place of business; whether applicant is an individual, partnership, corporation or otherwise; the state under the laws of which organized or authorized; the agency having jurisdiction over rates and tariffs and the name, title, and mailing address of the person or persons to whom communications concerning the application are to be addressed,

(2) A list of outstanding budget-type certificates held by the applicant issued pursuant to § 157.7, and

(3) A statement that the applicant will comply with the terms, conditions and procedures specified in this subpart.

§ 157.205 Notice procedure.

(a) *Applicability.* No transaction described in §§ 157.208(b), 157.209(b), 157.211(b), 157.212, 157.213(b), 157.214, or 157.216(b) is authorized by a blanket certificate issued under this subpart unless the notice requirements have been fulfilled in accordance with the provisions of this section and no protest has been filed in accordance with paragraph (d) of this section.

(b) *Submission of request by pipeline.* For any transaction subject to the requirements of this section, the certificate holder shall file with the Secretary of the Commission an original and fifteen copies of a request containing the following items:

(1) The exact legal name of the certificate holder and mailing address of the person or persons to whom communications concerning the request are to be addressed;

(2) The docket number in which its blanket certificate was issued;

(3) Any information required in § 157.208 through § 157.216 for the particular transaction;

(4) A verified statement that the proposed transaction complies with the requirements of this subpart; and

(5) A form of notice suitable for publication in the **Federal Register**, as contemplated by § 157.6(b)(7) and § 157.9, which briefly summarizes the facts contained in the request in such a way as to acquaint the public with its scope and purpose.

(c) *Publication of notice of request.* The Secretary shall publish a notice of the request as soon as it is practicable. The notice shall designate a deadline for filing protests or interventions to the request. The deadline shall be at least 45 days after the filing date of the request.

(d) *Protests.* (1) Any person or the Commission's staff may file a protest prior to the deadline established by the Secretary. Copies of the protest must be served on the Secretary of the Commission, the certificate holder, and any intervenor or other party protesting the requested authorization.

(2) Protests shall be filed in the following form:

United States of America Before the Federal Energy Regulatory Commission

[Name of Pipeline]

Docket No. [Include both docket No. of the blanket certificate and subdocket].

Protest to Proposed Blanket Certificate Transaction

[Name of Protestor] hereby protests the request filed by [Name of pipeline] to conduct a [sale, transportation, construction of facilities, abandonment, etc.] under § 157.—— of the Commission regulations. Protestor seeks to have this request processed as a separate application.

[Include a brief statement of Protestor's interest in the transaction and the grounds for the objection.]

(e) *Effect of protest.* If a protest is filed in accordance with paragraph (d) of this section, the transaction shall not be authorized by the blanket certificate. Instead, the request filed by the certificate holder shall be treated as an application for section 7 authorization

for the particular transaction. The **Federal Register** notice of the request shall be deemed to be notice of the section 7 application sufficient to fulfill the notice requirement of §§ 157.9 and 157.10

(f) *Final authorization.* If no protest is filed by any person or the Commission's staff within the deadline prescribed by the Secretary, the certificate holder shall be deemed to be authorized to conduct the transaction under its blanket certificate, effective upon the day after the deadline established by the Secretary

§ 157.206 Standard conditions.

Any transaction authorized under a blanket certificate issued pursuant to this subpart shall be subject to the following conditions:

(a) *Revisions.*

(1) The Commission reserves the right to amend the requirements of this subpart from time to time and to revoke any blanket certificate on 60 days notice.

(2) The blanket certificate is not transferable in any manner and shall be effective only so long as applicant continues the operations authorized by the order issuing such certificate and in accordance with the provisions of the Natural Gas Act, as well as applicable rules, regulations, and orders of the Commission.

(b) *Production-related costs.* At such time as the certificate holder proposes to recover in its rates any costs incurred by it to compress, process, treat, or gather natural gas purchased or transported by it, the pipeline may be required to prove that the activity which engendered those costs was prudent. In determining prudence, the Commission will apply the statement of policy set out under § 2.102 of this chapter.

(c) *Liquids and liquefiable hydrocarbons.* To the extent that the certificate holder transports substances other than natural gas (which are ultimately removed from the natural gas stream) pursuant to the blanket certificate or uses facilities authorized by the blanket certificate for the transportation of such substances, the certificate holder shall be required to allocate costs to the transportation of those substances. This certificate is issued without prejudice as to any action taken by the Commission in Phase II of the Louisiana First Use Tax proceeding in Docket No. RM78–23.

(d) *Environmental compliance.* (1) All transactions authorized by the blanket certificate shall be in full compliance with § 2.69 of this chapter.

(2) All transactions shall be consistent with the provisions of the following statutes and regulations or compliance plans developed to implement these statutes:

(i) Clean Water Act, as amended (33 U.S.C. 1251 et. seq.) and the National Pollution Discharge Elimination System Program, 40 CFR Part 122 et. seq.;

(ii) Clean Air Act, as amended (42 U.S.C. 1801 et. seq.) and air quality regulations and state implementation plans adopted pursuant to 40 CFR Parts 50 through 99;

(iii) Safe Drinking Water Act, as amended (42 U.S.C. 300f et. seq.);

(iv) National Historic Preservation Act of 1966 (16 U.S.C. 470 *et. seq.*);

(v) Archeological and Historic Preservation Act of 1974 (Pub. L. 93–291);

(vi) Coastal Zone Management Act of 1977, as amended (16 U.S.C. 1451 *et. seq.*);

(vii) Endangered Species Act of 1973, Pub. L. 93–205, as amended (16 U.S.C. 1531 *et. seq.*);

(viii) Executive Order 11988, May 24, 1977 requiring Federal agencies to evaluate the potential effects of any actions it may take on a floodplain;

(ix) Executive Order 11990, May 24, 1977 requiring an evaluation of the potential effects of construction on wetlands;

(x) Wild and Scenic Rivers Act (16 U.S.C. 1274 *et. seq.*);

(xi) National Wilderness Act (16 U.S.C. 1133 *et. seq.*);

(xii) National Parks and Recreation Act of 1978 (16 U.S.C. 1 and 230 *et. seq.*);

(xiv) Wildlife Restoration Act (16 U.S.C. 3669 *et. seq.*).

(3) Any transaction shall not significantly impact, or adversely affect:

(i) An endangered or threatened species as identified under the Endangered Species Act, or

(ii) A sensitive environmental area.

(4) Any compressor installed pursuant to the blanket certificate shall not increase ambient noise levels at nearby existing residences above a mean level (L_{dn}) of 55 dBA.

(e) *Budget-type certificates.* The certificate holder shall surrender any outstanding budget-type certificates issued pursuant to § 157.7 upon acceptance of a certificate issued pursuant to this subpart.

(f) *Commencement.* Any authorized construction, extension, or acquisition shall be completed and in actual operation by the certificate holder and any authorized operation, service or sale shall be actually undertaken within one year of the deadline for protests established by the Secretary under § 157.205(c).

(g) *Treatment of revenues.* (1) Except as provided in subparagraphs (2) and (3) of this paragraph, all revenues received for transportation (including storage service) authorized under the blanket certificate in excess of an allowance of one cent per MMBtu shall be credited to Account No. 191 and flowed back to the certificate holder's customers.

(2) A certificate holder is not required to credit revenues to Account No. 191 pursuant to subparagraph (1):

(i) To the extent revenues attributable to such services fall within representative levels which have been credited in arriving at a test period cost of service; or

(ii) To the extent that volumes transported fall within representative levels which have been included in billing determinants for the purpose of establishing rates.

(3) The certificate holder may elect to forego the one cent per MMBtu allowance provided in paragraph (g)(1) of this section. In such a case the certificate holder is not required to credit to Account No. 191 any amount which, upon application, the Commission finds to have been demonstrated as representing the out-of-pocket expenses of the certificate holder in connection with a transaction authorized under this Subpart.

(h) *Reports.* The certificate holder shall file reports as required by this subpart.

§ 157.207 General reporting requirements.

(a) *Annual report.* On March 1 of each year, the certificate holder shall file a statement, in writing and under oath, listing for the previous calendar year:

(1) For each new facility authorized by § 157.208: the information specified by § 157.208(e);

(2) For each transportation service authorized pursuant to § 157.209, the information specified by § 157.209(d);

(3) For each sales tap authorized pursuant to § 157.211(a); the information required by § 157.211(e);

(4) For each storage service authorized pursuant to § 157.213(a), the information specified in § 157.213(c);

(5) For each storage project tested or developed pursuant to § 157.215; the information specified by § 157.215(b)(1);

(6) For each abandonment authorized pursuant to § 157.216(a); the information specified by § 157.216(d);

(7) For each change in rate schedule authorized pursuant to § 157.217, the information specified in § 157.217(b); and

(8) For each change in customer name authorized pursuant to § 157.218, the information specified in § 157.218(b).

(b) *Subsequent reports.* If any significant change occurs with respect to the information filed under this section, the certificate holder shall file with the Commission within 30 days, under oath, appropriate amendments to its request or annual report, signed by a senior official of the company.

(c) *Final reports.* Within thirty days after the termination of any arrangement authorized under §§ 157.209, or 157.213, the certificate holder shall file with the Commission a report, under oath, signed

by a senior official of the company, stating:

(1) The identity of the certificate holder;

(2) The identity of all parties to the transaction;

(3) The dates of commencement and termination of the arrangement;

(4) Actual total and maximum daily volumes of natural gas transported pursuant to the arrangement;

(5) Total revenues received and a complete statement of the manner in which the revenues were treated;

(6) A brief explanation of the transaction; and

(7) In the case of transportation to an end-user authorized under §§ 157.209(a) or (b)(1), the information required by § 157.105(f).

(d) *Other reports.* For other reporting requirements see the individual sections §§ 157.208 through 157.218.

§ 157.208 Construction and operation of facilities.

(a) *Automatic authorization.* (1) Subject to the annual budget limitation of subparagraph (2), the certificate holder is authorized to construct and operate any minor facility whose project cost does not exceed the amount specified in line 1 of Table I.

(2) The total cost of all minor facility construction authorized pursuant to this paragraph during any calendar year under the blanket certificate shall not exceed the lesser of:

(i) The amount specified in line 2 of Table I; or

(ii) The greater of:

(A) $1,000,000 or

(B) Three percent (3%) of the certificate holder's net plant in Account No. 101. The dollar limit for construction during a partial calendar year shall bear the same proportion to the certificate holder's limit as the number of months in the calendar year bears to 12.

The certificate holder may apply to the Commission for a waiver of the calendar year dollar limit of this subparagraph for any year.

(b) *Prior notice.* Subject to the notice procedure of § 157.205, the certificate holder is authorized to construct and operate any minor facility whose project cost is greater than the amount specified in line 1 of Table I, but less than the amount specified in line 3 of Table I.

(c) *Contents of request.* Request filed pursuant to paragraph (b) shall contain:

(1) A description of the purpose of the proposed facilities;

(2) A detailed description of the proposed facilities specifying length, diameter and wall thickness for pipeline; and size, type, number of horsepower needed, installed and proposed, volume of fuel gas, suction and discharge pressures and compression ratio for compressors.

(3) A USGS 7½ minute series (scale 1:24000) topographic map (or map of equivalent detail) showing the location of the proposed facilities, and indicating the location of any sensitive environmental areas.

(4) A map showing the relationship of the proposed facilities to the applicant's existing facilities.

(5) Flow diagram or comparative study showing daily design capacity, daily maximum capacity and reflecting system operation with and without the proposed facilities added.

(6) Gas supply and market data/study or other circumstances supporting the need for the proposed facilities.

(7) The estimated cost and method of financing the project.

(8) A statement clearly showing the effect on the operating revenues and operating expenses of the estimated revenues and expenses related to the proposed facility.

(9) A statement explaining how the public convenience and necessity is served by approval of the project.

(10) A concise analysis which identifies the existing environmental conditions and the expected impacts and whether or not the proposed action will cause any significant impact to the quality of the human environment, including those expected to occur on sensitive environmental areas. The analysis shall also demonstrate that the proposed action shall be consistent with any applicable state coastal zone

management programs; state water quality management plans under the Clean Water Act of 1977 (Pub. L. 95–217, as amended) and Safe Drinking Water Act (Pub. L. 93–523, as amended) and State Implementation Plans developed under the Clean Air Act.

(d) *Inflation adjustment.* The limits specified in Table I shall be adjusted each calendar year to reflect the "GNP implicit price deflator" published by the Department of Commerce for the previous calendar year. The Director of the Office of Pipeline and Producer Regulation authorized to compute and publish limits for future calendar years as a part of Table I, pursuant to § 375.307(n) of this chapter.

Table I

Limit	1981
1. Automatic project cost limit	$3,500,000
2. Annual limit	36,000,000
3. Notice procedure limit	10,000,000

(e) *Reporting requirements.* By March 1 of the year following each calendar year during which a blanket certificate issued pursuant to this subpart is in effect, the certificate holder shall file an annual report which contains the following information:

(1) A description of the facilities installed pursuant to this section, including a description of the length and size of pipelines, compressor horsepower, metering facilities, taps, valves, and any other facilities constructed;

(2) The specific location of the facilities installed;

(3) The actual installed cost of each facility listed pursuant to paragraph (c)(1) of this section, separately stating the cost of materials and labor as well as other costs allocable to the facilities;

(4) The estimated gas supply in Mcf at 14.73 psia made available to the certificate holder by means of the described facilities;

(5) The names of the fields connected;

(6) The specific location of the supply source or well attached if the attachment is for gas owned or produced by the certificate holder;

(7) The names of the independent producers, other sellers or intrastate pipelines from whom the gas is being purchased or received, together with the respective dates of their gas sales or transportation contracts and any FERC gas rate schedule designations if the facility is to receive gas purchased by the applicant;

(8) A statement clearly reflecting whether the report is for a full calendar year or a partial year if the report is for the certificate holder's first blanket certificate year;

(9) The amount of the certificate holder's gas plant account (Account No. 101), as well as its computation of its calendar year and single project dollar limits;

(10) If no construction took place under the certificate, a statement to that effect.

(f) *Special conditions.* (1) For any project authorized under paragraph (b), the certificate holder shall file with the Commission, in writing and under oath, an original and four conformed copies and, upon request, shall furnish an intervener with a single copy, of the following:

(i) Within ten days after the bona fide beginning of construction, notice of the date of such beginning;

(ii) Each three months after filing notice of commencing construction, a progress report showing the exact status of authorized construction;

(iii) Within ten days after authorized facilities have been constructed and placed in service or any authorized operation, sale, or service has commenced, notice of the date of such placement and commencement; and

(iv) Within six months after authorized facilities have been constructed, a statement showing, on the basis of all costs incurred to that date and estimated to be incurred for final completion of the project, the cost of constructing authorized facilities, such total costs to be classified according to the estimates submitted in the certificate proceeding and compared therewith and any significant difference explained.

(2) In the interest of safety and reliability of service, facilities authorized by the certificate shall not be operated at pressures exceeding the maximum operating pressure set forth in the request as it may be amended prior to issuance of the certificate. In the event the certificate holder thereafter wishes to change such maximum operating pressure it shall file an appropriate petition for amendment of the authorization under the blanket certificate. Such petition shall include the reasons for the proposed change. Nothing contained herein authorizes the certificate holder to operate any facility at a pressure above the maximum prescribed by state law, if such law requires a lower pressure than authorized hereby.

§ 157.209 Transportation.

(a) *Automatic authorization.* The certificate holder is authorized to transport natural gas owned by a qualified end-user for ultimate consumption by the qualified end-user, for a term of up to 5 years, if:

(1) The sale of such natural gas is a first sale as defined in section 2(21) of the NGPA;

(2) Such natural gas was not committed or dedicated to interstate commerce on November 8, 1978.

(b) *Prior notice.* (1) Subject to the notice procedures of § 157.205, the certificate holder is authorized to transport natural gas in transactions described in paragraph (a)(1) for terms in excess of five years. Any request for transportation under this subparagraph shall include the information specified in § 157.103.

(2) Subject to the notice procedure of § 157.205, and subparagraph (3) of this paragraph, the certificate holder is authorized to transport natural gas on behalf of any:

(i) Local distribution company;

(ii) Interstate pipeline, or

(iii) Intrastate pipeline.

(3) No transportation is authorized under subparagraph (2) unless:

(i) The transportation can be performed using the existing capacity of the certificate holder, and

(ii) The transported natural gas is delivered directly or indirectly to an interstate pipeline, intrastate pipeline, or local distribution company, which receives such natural gas for its system supply.

(c) *Contents of request.* (1) Requests filed pursuant to paragraph (b) of this section shall include the information specified in § 157.103.

(2) Requests filed pursuant to paragraph (b)(2) shall include the information required in § 284.107 of this chapter.

(d) *Special conditions.* Any transportation authorized under either paragraphs (a) or (b) of this section shall be subject to the following conditions:

(1) The rates and charges shall be subject to in § 284.103 of this chapter;

(2) The contract for the transportation shall provide that service under the contract shall be subject to the availability of capacity sufficient to provide the service without detriment or disadvantage to the certificate holder's existing customers who are dependent upon the certificate holder's general system supply;

(3) For transportation authorized under paragraphs (a) or (b)(1) of this section, the volume transported shall not exceed the maximum permitted if the transportation had been authorized pursuant to certificates issued under § 2.79 of this chapter or Subpart E of this part; and

(4) Any transportation authorized under paragraphs (a) or (b)(1) is conditioned upon the end-use restrictions:

(i) Specified in § 2.79(m) applicable to eligible users as defined in § 2.79(c) of this chapter;

(ii) Specified in § 157.105 applicable to schools, hospitals and essential agricultural users; or

(iii) Specified from time to time in Commission orders authorizing

transportation to other designated categories of qualified end-users.

(d) *Reporting requirements.* (1) As a part of the annual report, the certificate holder shall file for each transaction authorized under paragraph (b)(2): The name of each customer receiving natural gas, the total and maximum daily deliveries to each customer, and the expiration date of the transportation arrangement;

(2) For each transaction authorized under paragraphs (a) or (b)(1) of this section, the information specified by § 157.105.

§ 157.210 Sales for resale [Reserved].

§ 157.211 Construction and operation of sales taps.

(a) *Automatic authorization.* The certificate holder is authorized to construct and operate sales taps for the delivery of gas to the end user if:

(1) the natural gas is ultimately delivered to and consumed by a right-of-way grantor; and

(2) no more than 200 MMBtu of natural gas per day are to be delivered to the right-of-way grantor.

(b) *Prior notice.* Subject to the notice procedure of § 157.205, the certificate holder is authorized to construct and operate sales taps, if:

(1) The natural gas is ultimately consumed by an end-user currently served directly or indirectly from the general system supply of the certificate holder,

(2) The volumes delivered are within the certificate entitlements of the customers, and

(3) The certificate holder's tariffs do not prohibit the addition of new delivery points.

(c) *Contents of request.* Requests filed pursuant to paragraph (b) should contain:

(1) The name of the end-user;

(2) The authority for the current sale to the end-user;

(3) The quantity of gas to be sold through the proposed facility,

(4) The rate or rate schedule applicable to the sale made through the proposed tap.

(d) *Reporting requirements.* As part of the certificate holder's annual report, the certificate holder shall report:

(1) The name of the end-user; and

(2) The maximum daily volumes to be sold.

(3) The actual cost of the sales tap.

(e) *Indirect customers.* The authorization in paragraphs (a) and (b) of this section shall apply irrespective of whether the certificate holder sells the natural gas directly to the end-user or the natural gas is delivered to the end-user, for the account of a local distribution company.

§ 157.212 Changes in delivery points.

(a) *Prior notice.* Subject to the notice requirements of § 157.205, the certificate holder is authorized to add new delivery points for a customer or to reassign volumes of gas to be delivered from one of the customer's delivery points to another, if:

(1) The total volumes to be delivered to the customer after the amendment does not exceed the total volumes authorized prior to the amendment;

(2) The change is not prohibited by an existing tariff of the certificate holder; and

(3) The certificate holder has sufficient capacity to accomplish the deliveries specified under the amendment without detriment or disadvantage to the certificate holder's other customers.

(b) *Contents of request.* When requesting any amendment authorized under paragraph (a) of this section, the certificate holder shall state:

(1) The name of the customer;

(2) The location of the delivery points;

(3) A citation to the certificate authorizing the delivery points; and

(4) The present and proposed quantities of natural gas to be delivered at each of the affected delivery points.

§ 157.213 Storage services.

(a) *Automatic authorization.* The certificate holder is authorized to provide contract storage services and any incidental transportation on behalf of any person, if:

(1) The storage service is within the certified capacity of the certificate holder's existing storage facilities;

(2) The storage arrangement does not exceed a period of two years;

(3) The rates charged for the storage and transportation service are covered by a currently effective rate schedule; and

(4) The contract for the storage service provides that the service under the contract shall be subject to the availability of capacity sufficient to provide the service without detriment or disadvantage to the certificate holder's existing customers who are dependent upon the certificate holder's general system supply.

(b) *Prior notice.* Subject to the notice requirements of § 157.205, the certificate holder is authorized to provide transportation and storage services specified in paragraph (a) of this section for periods in excess of 2 years.

(c) *Contents of request and reporting requirements.* In any annual report filed for transactions under paragraph (a) of this section and in any request for services authorized under paragraph (b) of this section, the certificate holder shall provide:

(1) The name of the customer;

(2) A copy of the storage service agreement;

(3) The storage facility proposed to be used;

(4) The amount of storage capacity in the facility rendered under the contract, and the amount of uncommitted storage capacity remaining after executing the storage service agreement, and

(5) The expiration date of the arrangement.

§ 157.214 Increase in storage capacity.

(a) *Prior notice.* Subject to the notice requirements of § 157.205, the certificate holder is authorized to increase the maximum volume of natural gas authorized to be stored in a storage field to the extent that geological data and operating experience have demonstrated that a volume of natural gas greater than that currently certificated may be safely stored without the construction of additional facilities.

(b) *Contents of request.* In any such request the following information shall be provided:

(1) Current and requested maximum storage capacity;

(2) Current and requested maximum storage pressure;

(3) Average depth of the storage formation; and

(4) Copies of any geological or engineering studies to demonstrate the feasibility of the increase in storage volume.

(c) *Reporting requirements.* For any storage facility whose capacity is increased pursuant to this section, the certificate holder shall submit semi-annual reports (to coincide with the termination of the injection and withdrawal cycles) containing the following information. The certificate holder shall continue to file semiannually reports until the storage inventory volume has reached or closely approximated the maximum specified in the request. Thereafter, the reports shall continue on a semiannual basis for a period of one year. At the end of the one year period, the filing of reports shall be discontinued unless otherwise ordered by the Commission. (Volumes shall be stated at 14.73 psia and 60°F, and pressure shall be stated in psia.)

(1) The daily volume of natural gas injected into and withdrawn from the storage reservoir.

(2) The volume of natural gas in the reservoir at the end of the reporting period.

(3) The maximum daily injection or withdrawal rate experienced during the reporting period. The average working pressure on such maximum days taken at a central measuring point where the total volume injected or withdrawn is measured.

(4) Results of any tracer program by which the leakage of injected gas may be determined. If the leakage of gas exists, the report should show the estimated total volume of gas leakage, the volume of recycled gas and the remaining inventory of gas in the reservoir at the end of the reporting period.

(5) Any surveys of pressures in gas wells, water levels in observation wells, pump test results for the aquifer type reservoirs, and the results of back-pressure tests conducted during the reporting period.

(6) For the reporting period, a summary of wells drilled, recompleted or worked-over, with subsea depth of formation and casing settings. Summarized results of reservoir characteristics from any logs or cores taken in well.

(7) The latest revised structure and isopachous contour maps showing the location of the wells, the location and extent of the gas bubble in the storage reservoir for aquifer type reservoirs and in any other reservoirs of the project in which gas bubbles are known to exist. This map need not be filed if there is no material change from the map previously filed.

(8) Discussion of current operating problems and conclusions.

(9) Such other data or reports which may aid the Commission in the evaluation of the storage project.

§ 157.215 Underground storage testing and development.

(a) *Automatic authorization.* The certificate holder is authorized to construct and operate natural gas pipeline and compression facilities for the testing and development of underground reservoirs for the possible storage of gas, if:

(1) The testing and development will be completed within a three year period;

(2) The quantity of natural gas to be injected into the prospective storage fields does not exceed a total of 10,000,000 MMBtu, with no more than 2,000,000 MMBtu being injected into any single field;

(3) Gas will be injected for testing purposes only during off-peak periods;

(4) The storage field developed pursuant to this section will not be utilized to render service without further authorization from the Commission; except that gas may be withdrawn on occasion for testing purposes;

(5) The total expenditures pursuant to this section do not exceed $1,000,000 per calendar year. These costs shall include expenditures for leases, wells, pipeline, compressors, and related facilities, but shall exclude the cost of the natural gas to be used for testing purposes.

(b) *Reporting requirements.* (1) *Annual reports.* For any storage project tested or developed pursuant to this section, the certificate holder shall file as part of its annual report:

(i) A description of the facilities constructed and the type of storage reservoir; i.e., gas expansion or dry gas, water-drive or aquifer,

(ii) The location of the facilities,

(iii) The cost of such facilities,

(iv) The monthly volumes of gas injected into and withdrawn from each reservoir, and

(v) An estimate of the storage capacity and daily deliverability of each project.

(2) *Quarterly reports.* If the reservoir to be tested and developed is an aquifer-type reservoir, the certificate holder shall file for each such project quarterly reports, under oath, containing the following information in addition to the data required by subparagraph (2) of this paragraph:

(i) The daily volumes of natural gas injected into and withdrawn from the aquifer during the quarter and the volume of gas in the aquifer at the end of each month.

(ii) The maximum daily injection or withdrawal rate experienced during the quarter and the average working pressure on such maximum days taken at a central measuring point where the total volume injected or withdrawn is measured.

(iii) Results of any tracer program by which leakage of gas may be determined.

(iv) Any pressure surveys of gas wells and water levels in observation wells conducted during the quarter by individual well. Copies of any core analyses, gamma ray, neutron or other electric log surveys and back-pressure tests taken during the quarter.

(v) A map of the storage project showing the location of the wells, the latest revised structure contours, the location and extent of the gas bubble. This map need not be filed if there is no material change from the map previously filed.

(vi) Such other data or reports which may aid the Commission in the evaluation of the project.

(vii) Reports shall continue to be filed quarterly until the project is either certificated for regular service or abandoned, unless otherwise ordered by the Commission.

(c) *Accounting.* The cost of any project ultimately determined to be infeasible for storage shall be charged to Account No. 822 of Part 201, Underground Storage Exploration and Development Expenses.

§ 157.216 Abandonments.

(a) *Automatic authorization.* The certificate holder is authorized pursuant to section 7(b) of the Natural Gas Act to abandon gas supply facilities, if:

(1) The supplier has been authorized to abandon its sale; or

(2) No abandonment of the supplier's sale is required under the Natural Gas Act by operation of section 601(a)(1) of the NGPA.

(b) *Prior notice.* Subject to the notice requirements of § 157.205, the certificate holder is authorized pursuant to section 7(b) of the Natural Gas Act to abandon any sales tap or lateral line and related facilities and service if all of the buyers currently served through the sales tap or lateral line consent in writing to the abandonment.

(c) *Contents of request.* Any request submitted pursuant to paragraph (b) shall describe:

(1) The location of the subject facilities;

(2) The docket authorizing the construction and operation of the facilities to be abandoned;

(3) An oath statement that all of the customers served by the subject facilities have consented to the abandonment, or an explanation of why the customers' consent is not available; and

(4) A proposed accounting treatment of any facilities to be abandoned.

(d) *Reporting requirements.* The annual report filed by the certificate holder should contain, for each abandonment:

(1) The name of the seller,

(2) The docket number of the certificate authorizing the sale,

(3) Of the full sale, and accounting treatment of the facilities, abandoned.

§ 157.217 Changes in rate schedules.

(a) *Automatic authorization.* The holder of a blanket certificate is authorized to permit an existing customer to change from one rate schedule to another, if:

(1) The combined volumetric limitations on deliveries to the customer under both rate schedules are not increased, for either annual or peak day limitations; and

(2) The changes are consistent with the terms of effective tariffs on file with the Commission.

(b) *Reporting requirements.* In the annual report for any year in which the certificate holder has permitted an existing customer to change from one rate schedule to another pursuant to this section the certificate holder shall state:

(1) The name of the customer; and

(2) The rate schedules involved and a citation to the certificate which authorized the service to the customer.

§ 157.218 Changes in customer name.

(a) *Automatic authorization.* The outstanding certificates of the certificate holder may be amended to the extent

necessary to reflect the change in the name of an existing customer, if:

(1) The change in customer is the result of a corporate reorganization or acquisition;

(2) The certificate holder has filed any necessary conforming changes in its tariffs; and

(3) The customer's use of gas will not be affected by the change in name.

(b) *Reporting requirements.* For each customer name change authorized during a calendar year, the certificate holder shall include as a part of its annual report:

(1) The old and new names of the party;

(2) A brief explanation of the reason for the name change; and

(3) A list of all affected certificates.

PART 375—[AMENDED]

2. Section 375.307 is amended by adding new paragraphs (a)(11) and (n) to read as follows:

§ 375.307 Delegations to the Director of the Office of Pipeline and Producer Regulations.

The Commission authorized the Director of the Office of Pipeline and Producer Regulation or the Director's designee to:

(a) Pass upon the following types of uncontested applications or contested amendments to applications: • • •

(11) Applications for blanket certificates of public conveniences and necessity pursuant to Subpart F of Part 157.

• • • • •

(n) Compute, for each calendar year, pursuant to § 157.208 of this chapter, the project limits specified in Table I of that section adjusted for inflation, and to publish such limits as soon as possible thereafter in the **Federal Register**.

¶ 32,118 High-Cost Gas Produced From Tight Formations (West Virginia-1)

46 F. R. 16914 (March 16, 1981)

18 CFR Part 271

[Docket No. RM79-76 (West Virginia-1)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of West Virginia Office of Oil and Gas that the Ravencliff, Injun-Squaw, Weir and Berea Formations be designated as tight formations under § 271.703(d).

DATE: Comments on the proposed rule are due on April 8, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet Written requests for a public hearing are due on March 24, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Ting Chin, (202) 357-8595/John Bassett, (202) 357-8589.

SUPPLEMENTARY INFORMATION:

Issued: March 9, 1981.

I. Background

On February 20, 1981, the State of West Virginia Office of Oil and Gas (West Virginia) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Ravencliff Formation, Injun-Squaw Formation, Weir Formation and Berea Formation, located in Fayette and Raleigh Counties, West Virginia, be designated as tight formations in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether West Virginia's recommendation that the Ravencliff, Injun-Squaw, Weir and Berea Formations be designated as tight formations should be adopted. West Virginia's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The four recommended formations lie within portions of Fayette and Raleigh Counties, West Virginia. (A more detailed description of the recommended area is contained in the recommendation on file with the Commission.) All four formations are Mississippi Age deltaic sandstone deposits. The Revencliff Formation lies below the Princeton Sandstone and above the Maxton Sandstone. The Ravencliff Formation ranges in thickness from thin stringers in the eastern portion of the two counties to a maximum thickness of 140 feet in the

central portion of the area. The Injun-Squaw Formation lies below the Big Lime-Keener Formation and above the Weir Formation. The Injun-Squaw Formation ranges in thickness from a maximum of 20 feet in northwestern Fayette County to thin stringers to the south and east. The Weir Formation lies approximately 200 feet below the Injun-Squaw Formation and approximately 200 feet above the Berea Formation. The Weir Formation ranges in thickness from 50–80 feet in the northeastern part of the recommended area to 100 feet in the southern portion of the area. The Berea Formation lies approximately 200 feet below the Weir Formation. The Berea Formation ranges in thickness from 55 feet in northwestern Fayette County to thin shaly sandstone stringers in the southern portion of the recommended area.

III. Discussion of the Recommendation

West Virginia claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by West Virginia on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay sections of the proposed areas is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formations is expected to produce more than five (5) barrels of oil per day.

West Virginia further asserts that existing State and Federal Regulations will assure that development of the Ravencliff, Injun-Squaw, Weir and Berea Formations will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply. Protection of fresh water aquifers will be assured by enforcing compliance with Section 15, Part 1, Section V of the West Virginia Administrative Regulations and Chapter 22–4–8a of the Code of West Virginia.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980 in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by West Virginia that the Ravencliff, Injun-Squaw, Weir and Berea Formations, as described and delineated in West Virginia's recommendation as filed with the Commission, be designated as tight formations pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before April 8, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (West Virginia—1), and should give reasons, including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at the public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the

Commission no later than March 24, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event West Virginia's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraphs (36) through (39) to read as follows:

§ 271.703 Tight Formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(19) through (35) [Reserved]

(36) *Ravencliff Formation in West Virginia.* RM79–76 (West Virginia—1)

(i) *Delineation of Formation.* The Ravencliff Formation underlies portions of Fayette and Raleigh Counties, West Virginia.

(ii) *Depth.* The Ravencliff Formation lies below the Princeton Sandstone and above the Maxton Sandstone. Within the recommended area the Ravencliff Formation ranges in thickness from thin stringers in the eastern portion of the two counties to a maximum thickness of 140 feet in the central portion of the area.

(37) *Injun-Squaw Formation in West Virginia.* RM 79–76 (West Virginia—1)

(i) *Delineation of formation.* The Injun-Squaw Formation underlies portions of Fayette and Raleigh Counties, West Virginia.

(ii) *Depth.* The Injun-Squaw Formation lies below the Big Lime-Keener Formation and above the Weir Formation. The Injun-Squaw Formation ranges in thickness from a maximum of 20 feet in northwestern Fayette County to thin stringers to the south and east.

(38) *Weir Formation in West Virginia.* RM79–76 (West Virginia—1)

(i) *Delineation of formation.* The Weir Formation underlies portions of Fayette and Raleigh Counties, West Virginia.

(ii) *Depth.* The Weir Formation lies approximately 200 feet below the Injun-Squaw Formation and approximately 200 feet above the Berea Formation. The Weir Formation ranges in thickness for 50–80 feet in the northeastern part of the recommended area to 100 feet in the southern portion of the area.

(39) *Berea Formation in West Virginia.* RM79–76 (West Virginia—1)

(i) *Delineation of formation.* The Berea Formation underlies portions of Fayette and Raleigh Counties, West Virginia.

(ii) *Depth.* The Berea Formation lies approximately 200 feet below the Weir Formation. The Berea Formation ranges in thickness from 55 feet in northwestern Fayette County to thin shaly sandstone stringers in the southern portion of the recommended area.

¶ 32,119 Revision of Commission Rules of Practice; Procedures to Expedite Trial-Type Hearings

46 F. R. 17023 (March 17, 1981)

18 CFR Parts 1, 1b, 2, 3, 3a, 3c, 4, 12, 16, 25, 32, 33, 35, 41, 131, 152, 153, 154, 156, 157, 158, 250, 270, 271, 275, 281, 282, 284, 286, 292, 375, 385, and 388

[Docket No. RM78-22 (Part 7)]

Revision of Commission Rules of Practice; Procedures To Expedite Trial-Type Hearings

March 9, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: Federal Energy Regulatory Commission proposes to revise its Rules of Practice and Procedure which govern the conduct of Commission proceedings. The purpose of the revision is to expedite Commission proceedings and to establish uniform procedures for proceedings arising from various statutes administered by the Commission.

DATES: Hearing on May 19, 1981 at 10:00 a.m. Written comments by June 1, 1981.

ADDRESS: Comments should be sent to and hearing will be held at: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (Reference Docket No. RM78-22, Part 7).

FOR FURTHER INFORMATION CONTACT:

MaryJane Reynolds, Office of Commissioner Hughes, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8388.

Christine P. Benagh, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8606.

SUPPLEMENTARY INFORMATION:

I. Introduction and Summary

This rulemaking has three objectives. First, it proposes new procedural rules for cases which may be set for hearing. These new rules are contained in Subparts A, B, E, F, G, and T of the new Part 385. They would replace parallel provisions in Part 1.

Second, it would implement one step in the new organization for the procedural rules. It would remove from Part 1 the remaining rules of practice and place them in Subparts H, I, J, K, M, S, U, and V of Part 385. It also removes the public information regulations from Part 1 and places them in Part 388.

Third, it would make oil pipeline proceedings subject to the Commission rules with two exceptions: the ICC ex parte rule and ICC modified procedures would remain applicable to oil pipeline matters pending Commission rules on these subjects. No other procedural rules of the ICC would apply to oil pipeline proceedings.

II. Background

Since its inception in 1977, the Commission has been faced with a substantial backlog and numerous proceedings which had been pending for a number of years. In mid-1978, it undertook an examination of its decisionmaking process. To this end, the Commission established an Advisory Committee on the Rules of Practice and Procedure. One of the Subcommittees was asked to focus on the Hearing procedures.[1] The work product of that Subcommittee is the subject of this rulemaking.

There are two primary objectives in this proposed rulemaking: to create a

[1] Staff prepared two discussion drafts on revisions of the hearings procedures. These drafts were the subject of two public meetings of the Subcommittee. The drafts and transcripts of the meetings are available for inspection at the Commision's Division of Public Information.

comprehensive set of rules that can be easily understood by all persons affected by Commission action and to recommend new hearing procedures that would remove unnecessary work from the Commission's agenda and expedite decisionmaking by the Commission.

The need for reorganized and comprehensive procedural rules is compelling. The DOE Act conferred upon the Commission many functions of the old Federal Power Commission ("FPC") as well as the oil pipeline ratemaking functions of the Interstate Commerce Commission ("ICC"). Savings provisions in the DOE Act (42 U.S.C. 7295) continued the effectiveness of FPC and ICC regulations for Commission proceedings previously conducted by those agencies until such time as the Commission promulgates its own procedural rules. Accordingly, at this time, the Commission operates under two unreleated sets of rules. This, of course, is difficult and confusing for both the Commission and the public. Equally confusing is the fact that in many respects the existing rules are obsolete and do not accurately reflect current Commission practice.

Work on these proposed rules has led to the conclusion that a complete reorganization of the procedural rules was necessary to achieve a set of rules that could be easily found and understood. The general reorganization, which extends beyond the parameters of this proposed rule are described in III. *Reorganization, infra.*

The need to expedite proceedings is self-evident. Various proposals to do this are discussed in IV. *Discussion of the Proposed Rule, infra.* They include delegations to the Chief Administrative Law Judge to consolidate and sever. They would also allow the Presiding Administrative Law Judge to phase cases and to summarily dispose of issues or an entire proceeding without full hearing. Suggestions on additional ways to expedite hearings are most welcome.

The efforts in this rulemaking were directed to rules that would apply to cases which might be set for hearing. This, of course, includes rules for all types of pleadings, including petitions, applications, answers, and motions. It would require repeal of a number of the provisions in Part 1. Since the provisions proposed to be repealed were an integral part of the rules that were not being replaced, we have moved the remaining rules (those not directly involving cases which might be set for hearing) to the new Part 385. These transferred provisions are explained in more detail in Part IV, B.

III. The Proposed Reorganization

In March 1980 the Commission initiated the reorganization and updating of its Procedural Rules. It placed its rules relating to its establishment and internal management of the Commission in Subchapter W, Parts 375 and 376. Simultaneously, it revoked obsolete and parallel provisions that were previously scattered throughout Subchapter A, Parts O, 1, and 3.

This rulemaking would implement the second major step in the reorganization. It would place all Commission rules concerning the conduct of business by members of the public in a new Subchapter X. Specifically, Part 385 would contain rules of practice and procedure. Parts 386 and 387 would be reserved and Part 388 would contain the provisions concerning access to public information. It would also repeal all provisions currently found in Part 1 (except Subpart A) since these provisions would be contained in Parts 385 and 388. Part 1 would be solely for definitions and rules that are used throughout all Commission regulations.

The following chart indicates our present plan for reorganization. It includes not only the new and proposed Parts 375, 376, 385, and 389 but also indicates Parts tentatively assigned to rules which have not yet been

promulgated and which are not part of this rulemaking, e.g., Part 380, Environmental Policy Act Regulations. It also indicates where some existing Commission Rules will be recodified, e.g., Part 379, Standards of Conduct for Commission Employees.

TITLE 18—CODE OF FEDERAL REGULATIONS

CHAPTER 1—FEDERAL ENERGY REGULATORY COMMISSION

Subchapter A

Part
1—Definitions Used in This Chapter.
2—General Policy and Interpretations.
3—Reserved.

Subchapter W

375—The Commission.
376—Organization, Mission and Functions, Operations During Emergency Conditions.
377—National Security Information.
378—Privacy Act Regulations.
379—Standards of Conduct for Commission Employees.
380—National Environmental Policy Act Rules.
381–384—Reserved.

Subchapter X

385—Rules of Practice and Procedure.
386—Investigations.
387—Reserved.
388—Freedom of Information Act Rules.
389–399—Reserved.

IV. Discussion of the Proposed Rule

A. *New rules on hearing procedures.* Subparts A, B, E, F, G, and T of proposed Part 385 are new provisions, often representing substantial revisions to corresponding provisions in the current regulations. Particular issues upon which the Commission has focused are highlighted below in the context of the summary of each of the revised subparts. Staff has prepared two memoranda. One discusses the derivation of the proposed rules and details distinctions between the proposed and current rules. The second is a derivation table that indicates the sections of the current rule that are being replaced by the proposed rule. Although they are not official Commission documents, they are available in the Division of Public Information to assist persons in their preparation of comments.

Subpart A of Part 385 describes the applicability of Part 385 and defines common terms used throughout the part. Subpart A also codifies Commission authority to waive its procedural rules for good cause. Some members of the Advisory Committee were concerned that abuses could arise under the waiver provision. However, the Commission believes that the public interest is protected by the Commission's recognition that it may not exercise waiver authority if to do so would unduly prejudice persons appearing before the Commission.

Subpart B contains the general rules governing tariff or rate filings, applications, complaints, petitions, protests to oil pipelines valuations, notices of tariff or rate examination, orders to show cause, protests, motions, answers, interventions, amendments, withdrawal of pleadings, and summary disposition. This subpart corresponds to portions of §§ 1.5–1.12 of the present rules, and is generally applicable whenever these procedures are used in proceedings before the Commission.

The proposed rule condenses many of the current pleadings requirements. It departs from the current rules in some respects in order to expedite, simplify or clarify the procedures. The sections regarding tariff or rate schedule filings, protests to oil pipeline valuations, notices of examinations of tariffs or rate schedules, and summary disposition (Rules 205, 208, 209 and 216, respectively) are new, although they reflect current Commission practice.

The proposed intervention rule (Rule 213) contains three changes from current practice. First, it makes intervention automatic when there is no opposition. Second, the proposed rule contains stricter standards for late interveners to discourage late intervention. Finally, under the current rule, State commissions may intervene at any time by filing a notice of intervention. We retain notice procedure for State commissions if their intervention is

timely, but if they are late they must file a motion to intervene like private parties. There is some concern that the possibility that a State Commission may be denied intervention for filing late would present a more serious disadvantage to the Commission than that caused by late intervention.

Subpart B also codifies, in Rule 216, the current Commission practice of allowing summary disposition by a presiding officer of a proceeding or portion of a proceeding, even though the Commission has set the proceeding for hearing.

Subpart B, in Rule 211, requires that protests be served on the person who is the subject of the protest, but delegates to the Secretary the authority to waive the service requirement. In all cases the protest is to be placed in the public file. Certain members of the Advisory Committee expressed concern that the absence of this waiver provision might prevent persons unfamiliar with formal Commission practice from being heard in protest to a given tariff or rate. However, the Commission believes that the Secretary should waive the service rule judiciously.

Subparts C and D are reserved for future rules. Subpart D is tentatively set aside for new discovery rules that are being developed. Pending promulgation of new rules, the existing provisions on subpoenas and depositions would be continued in effect and recodified in Rules 1905 and 1906. We note, however, that Rules 1905 and 1906 would apply to all pipeline proceedings until new discovery rules are promulgated for all Commission proceedings. We believe the need for uniform rules outweigh the inconvenience that might arise from adjusting to the existing FPC rules and then adjusting to any changes in these rules at a later time. However, we specifically seek comment on this conclusion.

Subpart E applies to proceedings which the Commission sets for hearing under the subpart. Under the proposed rule, these are proceedings in which, unless sooner disposed of, a decision is made by a presiding officer after an on-the-record hearing. Proceedings to fix rates or concerning the grant of certificates or licenses under the Federal Power Act, the Natural Gas Act, or the Interstate Commerce Act, would usually be conducted under these rules. The subpart deals with hearings, consolidation and severance, presiding officers, witnesses, testimony, exhibits, evidence, stipulations, and transcripts. The proposed rule rearranges and simplifies corresponding sections of the Commission's rules (§§ 1.20–1.27). It recodifies the substance of the current rule on evidence. However, the Commission is tentatively considering the possibility of reworking this rule to more closely conform to the *Federal Rules of Evidence* and seeks comment on initiating a separate rulemaking docket for this purpose.

Subpart E departs from the current rules in several ways. In particular, the provisions on consolidation and severance, Rule 503, would delegate this authority to the Chief Administrative Law Judge rather than to the Secretary, as in the current rule. Administrative law judges would also have the authority to phase a proceeding. Oral testimony not conducted in the presence of presiding officer and written cross-examination have been suggested to the Commission as useful ways to expedite hearings (Rule 502). The Commission does not propose their adoption in this rulemaking. They are included in Rule 506 in order to obtain comments with respect to them.

Subpart F includes provisions on conferences, offers of settlement, and settlement judges. The provisions on conferences, Rule 601, encourages pre-hearing conferences in cases set for hearing. The rules also encourage the use of a conference to reach a settlement prior to a hearing. The proposed provisions on settlement offers and settlement judges, Rule 603, contain no major substantive changes from the current rules, which were recently promulgated (Order 32, "Amendment to § 1.18 of the Rules of Practice and Procedure," 45 FR 45,902, (July 8, 1980)).

The new rules add that the Oil Pipeline Board may approve or disapprove settlement offers, subject to appeal to the Commission.

Subpart G governs decisions and administrative review of decisions in proceedings set for hearing under Subpart E, and in other proceedings designated by the Commission. It contains provisions on decisions generally, participants' rights, briefs, oral argument, types of decision, exceptions to decisions, Commission review, certified questions, interlocutory appeals, rehearing, and reopening. The subpart simplifies and clarifies rules which now appear in §§ 1.29 through 1.34. The proposed rule requires the preparation of an initial decision in which a presiding officer, other than the Commission, has presided over the reception of evidence. However, the Commission may order a different decisionmaking procedure under section 557 of title 5 of the *United States Code*.

As redrafted, the rules eliminate the confusing distinctions in the current rules between intermediate, recommended, and tentative decisions. The proposed rule also affords participants the right to either file initial briefs or make oral arguments. The presiding officer is to decide which of the two options, or both, is to be granted to participants. Participants also may submit reply briefs or make oral argument unless prohibited or restricted by the presiding officer. As a general rule, participants are required to file their briefs simultaneously.

A new provision is added at the exceptions stage of a proceeding, providing that failure to take exception to an initial decision will result in a waiver of taking exception at a later time.

Subpart T applies to all Commission proceedings, rather than only those held on-the-record. It would revise the manner in which pleadings and other documents are prepared, filed, docketed, noticed, and served. It would also control time deadlines and their extension.

B. *Renumbered Provisions.* Subparts H, I, J, K, M, S, U, and V of Part 385 and all of Part 388 (which would be established by this rule) are portions of the current Rules of Practice and Procedure that the Commission proposes to renumber, without substantive change, so as to integrate them into the new organizational structure. The following chart indicates the section of current FPC regulations to which each of these subparts corresponds. The only changes made to the provisions contained in these subparts are technical, conforming and clarifying. The Commission seeks limited comment in these provisions. At this time, we merely wish to ascertain whether these renumbered provisions have been properly integrated with the newly written provisions of Subparts A, B, E, F, G, and T. The Commission requests that no comments be submitted at this time on the renumbered, but unchanged provisions. These renumbered provisions will be the subject of subsequent rulemaking. At that time, we will seek comments on the merits of these procedures. Some of these provisions were adopted by the Commission as interim rules; the renumbering proposed here would not affect that status.

Renumbered provision	Current provision
Part 385:	Part 1:
Subpart H—Shortened procedures.	§ 1.32.
Subpart I—Commission review of remedial orders.	§ 1.38.
Subpart J—Commission review of adjustment request denials.	§ 1.40.
Subpart K—Petitions for adjustment under the NGPA.	§ 1.41.
Subpart M—Cooperive procedure with state commissions.	§ 1.37.
Subpart S—Miscellaneous	§ 1.7(d), § 1.19(a), §§ 1.21, 1.23, §§ 1.24, 1.35.
Subpart U—Appearance and practice before the Commission.	§ 1.4 (except (d)).
Subpart V—Ex Parte communications; Separation of functions of staff.	§ 1.4(d), § 1.30(f).
Part 388: Public information and requests.	§ 1.36.

the United States (other than the Federal Energy Regulatory Commission), or any corporation which is owned directly or indirectly by the United States or any officer, agent, or employee of any of the foregoing acting as such in the course of his or her official duty. The term also includes a foreign government or any agency, authority, or instrumentality thereof.

(l) "State Commission" means the regulatory body of any State or municipality having jurisdiction to regulate rates or charges for the sale of electric energy or natural gas to consumers of for the transportation of oil by pipeline within the State or municipality.

* * * * *

Subpart B—[Reserved]

3. Chapter I is further amended by adding a new Subchapter X consisting of Parts 385 and 388 to read as follows:

SUBCHAPTER X—PROCEDURAL RULES

Part

385 Rules of practice and procedure.
388 [Reserved]
387 [Reserved]
388 Public information and requests.
389—399 [Reserved]

PART 385—RULES OF PRACTICE AND PROCEDURE

Subpart A—Applicability and Definitions

Sec.

385.101 Applicability. (Rule 101).
385.102 Definitions. (Rule 102).
385.103 References to, and citation of, rules. (Rule 103).

Subpart B—Pleadings, Tariff or Rate Filings, Notices of Tariff or Rate Examination, Orders To Show Cause, Intervention and Summary Disposition

385.201 Applicability. (Rule 201).
385.202 Types of pleadings. (Rule 202).
385.203 Content of pleadings and tariff or rate filings. (Rule 203).
385.204 Applications. (Rule 204).
385.205 Tariff or rate filings. (Rule 205).
385.206 Complaints. (Rule 206).
385.207 Petitions. (Rule 207).

Sec.

385.208 Notices of protest to tentative oil pipeline valuations. (Rule 208).
385.209 Notices of tariff or rate examination and orders to show cause. (Rule 209).
385.210 Notice. (Rule 210).
385.211 Other protests. (Rule 211).
385.212 Motions. (Rule 212).
385.213 Answers. (Rule 213).
385.214 Intervention. (Rule 214).
385.215 Amendment of pleadings. (Rule 215).
385.216 Withdrawal of pleadings. (Rule 216).
385.217 Summary dispositon. (Rule 217).

Subpart C-D—[Reserved]

Subpart E—Hearings

385.501 Applicability. (Rule 501).
385.502 Initiation of hearing. (Rule 502).
385.503 Consolidation and severance by Chief Administrative Law Judge. (Rule 503).
385.504 Duties and powers of presiding officers. (Rule 504).
385.505 Right of participants to present evidence. (Rule 505).
385.506 Examination of witnesses. (Rule 506).
385.507 Prepared written testimony. (Rule 507).
385.508 Exhibits. (Rule 508).
385.509 Admissibility of evidence. (Rule 509).
385.510 Miscellaneous provisions. (Rule 510).

Subpart F—Conferences, Settlements, and Stipulations

385.601 Conferences. (Rule 601).
385.602 Submission of settlement offers. (Rule 602).
385.603 Settlement negotiations before a settlement judge. (Rule 603).
385.604 Refusal to make admissions or stipulations. (Rule 604).

Subpart G—Decisions

385.701 Applicability. (Rule 701).
385.702 Definitions. (Rule 702).
385.703 Contents of decisions. (Rule 703).
385.704 Rights of participants before initial decision. (Rule 704).
385.705 Additional powers of presiding officer with respect to briefs. (Rule 705).
385.706 Initial and reply briefs before initial decision. (Rule 706).
385.707 Oral argument before initial decision. (Rule 707).
385.708 Initial decisions by presiding officer. (Rule 708).

Sec.

385.709 Other types of decisions. (Rule 709).
385.710 Waiver of the initial decision. (Rule 710).
385.711 Exceptions and briefs on exceptions after initial decision. (Rule 711).
385.712 Commission review of initial decision in the absence of exceptions. (Rule 712).
385.713 Request for rehearing. (Rule 713).
385.714 Certified questions. (Rule 714).
385.715 Interlocutory appeals to the Commission from rulings of presiding officers. (Rule 715).
385.716 Reopening. (Rule 716).

Subpart H—Shortened Procedures

385.801 Waiver of hearing. (Rule 801).
385.802 Noncontested proceedings. Rule 802).

Subpart I—Commission Review of Remedial Orders

385.901 Scope. (Rule 901).
385.902 Definitions. (Rule 902).
385.903 Request for nondisclosure of information. (Rule 903).
385.904 Commencement of proceeding. (Rule 904).
385.905 Stay of contested order. (Rule 905).
385.906 Pleadings. (Rule 906).
385.907 New facts and issues. (Rule 907).
385.908 Discovery. (Rule 908).
385.909 Hearing. (Rule 909).
385.910 Conduct of the hearing. (Rule 910).
385.911 Burden of proof. (Rule 911).
385.912 Proposed findings of fact, conclusions of law, and comments. (Rule 912).
385.913 Proposed order. (Rule 913).
385.914 Commission action. (Rule 914).
385.915 Ex parte communications. (Rule 915).
385.916 Withdrawal of petition for review. (Rule 916).
385.917 Sanctions. (Rule 917).

Subpart J—Commission Review of Adjustment Request Denials

385.1001 Scope. (Rule 1001).
385.1002 Definitions. (Rule 1002).
385.1003 Request for nondisclosure of information. (Rule 1003).
385.1004 Commencement of proceedings. (Rule 1004).
385.1005 Replies. (Rule 1005).
385.1006 Request for hearing. (Rule 1006).
385.1007 Presiding officer. (Rule 1007).
385.1008 Hearings. (Rule 1008).
385.1009 Proof. (Rule 1009).

Sec.

385.1010 Proposed order. (Rule 1010).
385.1011 Final order. (Rule 1011).
385.1012 Ex parte communications. (Rule 1012).

Subpart K—Petitions for Adjustments Under the NGPA

385.1101 Applicability. (Rule 1101).
385.1102 Definitions. (Rule 1102).
385.1103 Commencement of proceeding. (Rule 1103).
385.1104 Initial petition. (Rule 1104).
385.1105 Intervention. (Rule 1105).
385.1106 Other filings. (Rule 1106).
385.1107 Evaluations. (Rule 1107).
385.1108 Criteria. (Rule 1108).
385.1109 Orders. (Rule 1109).
385.1110 Review of initial decision and order for adjustment. (Rule 1110).
385.1111 Conferences. (Rule 1111).
385.1112 Requests for confidential treatment. (Rule 1112).
385.1113 Interim relief. (Rule 1113).
385.1114 Motions. (Rule 1114).
385.1115 Procedural rulings. (Rule 1115).
385.1116 Appeals. (Rule 1116).
385.1117 Application for adjustment treatment as request for interpretation. (Rule 1117).

Subpart L—[Reserved]

Subpart M—Cooperative Procedure With State Commissions

385.1301 Policy. (Rule 1301).
385.1302 Notice. (Rule 1302).
385.1303 Conferences. (Rule 1303).
385.1304 Procedure governing matters referred to a board. (Rule 1304).
385.1305 Joint and concurrent hearings. (Rule 1305).
385.1306 Intervention by state commissions. (Rule 1306).

Subpart N-R—[Reserved]

Subpart S—Miscellaneous

385.1901 Interpretations and interpretative rules under NGPA. (Rule 1901).
385.1902 Appeals from action of staff. (Rule 1902).
385.1903 Notice in rulemaking proceedings. (Rule 1903).
385.1904 Copies of transcripts. (Rule 1904).
385.1905 Subpoenas. (Rule 1905).
385.1906 Depositions. (Rule 1906).
385.1907 Reports of compliance. (Rule 1907).

Subpart T—Formal Requirements for Filings in Proceedings Before the Commission

385.2001 Filings. (Rule 2001).
385.2002 Caption of filings. (Rule 2002).
385.2003 Specifications. (Rule 2003).
385.2004 Copies of filings. (Rule 2004).
385.2005 Subscription and verification. (Rule 2005).
385.2006 Docket system. (Rule 2006).
385.2007 Time. (Rule 2007).
385.2008 Extension of time. (Rule 2008).
385.2009 Notice. (Rule 2009).
385.2010 Service. (Rule 2010).

Subpart U—Appearance and Practice Before the Commission

385.2101 Appearances. (Rule 2101).
385.2102 Suspension. (Rule 2102).
385.2103 Appearance of former employees. (Rule 2103).

Subpart V—Ex Parte Communications; Separation of Functions

385.2201 Ex Parte communications. (Rule 2201).
385.2202 Separation of functions of staff. (Rule 2202).

Subpart W-Z—[Reserved]

Authority: Administrative Procedure Act, 5 U.S.C. 551–557; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Federal Power Act, 16 U.S.C. 791–828C, as amended; Natural Gas Act, 15 U.S.C. 717–717w, as amended; Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.;* Public Utilities Act, of 1978, 16 U.S.C. 2601 *et seq.;* Interstate Commerce Act, 49 U.S.C. 1 *et seq.;* 12009, 3 CFR, 1977 Comp., p. 142.

Subpart A—Applicability and Definitions

§385.101 Applicability. (Rule 101.)

(a) *General rule.* This part contains procedural rules for filings and proceedings.

(b) *Exceptions.* (1) This part does not apply to formal investigations under Part 1b of this chapter.

(2) If a provision of Part 385 is inconsistent with another provision of this chapter, the latter provision controls.

(3)(i) Part 385 replaces the Interstate Commerce Commission *General Rules of Practice,* 49 CFR Part 1100, except that §§1100.42 through 1100.52 (modified procedure) and Appendix C to Part 1100 (ex parte) continue to apply to oil pipeline matters.

(ii) If a provision of Part 385 is inconsistent with a provision of Title 49 of the *Code of Federal Regulations* concerning oil pipeline matters which has not been replaced by Commission rule or order, the latter provision controls.

(c) *Waiver.* For good cause the Commission may waive, to the extent permitted by law, any provision in this part or provide for a different procedure.

§385.102 Definitions. (Rule 102.)

For purposes of this part:

(a) "Decisional authority," with respect to any question, means the Commission or Commission employee (including the Oil Pipeline Board) who at the time of the decision on such question has the authority or responsibility under this chapter, and under applicable provisions of Title 49 of the *Code of Federal Regulations,* to act with respect to that question.

(b) "Participant" means (1) a party, or (2) an employee of the Commission assigned to present the position of the Commission staff in a proceeding before the Commission.

(c) "Party" means (1) a person who files an application, petition, tariff or rate filing, complaint, or protest under section 19a(i) of the Interstate Commerce Act (49 U.S.C. 19a(i)), (2) a respondent to a proceeding, or (3) a person who has been permitted to intervene in a proceeding.

(d) "Presiding officer" (1) when used with respect to a proceeding set for hearing Subpart E of this chapter, means one or more of the members of the Commission or one or more administrative law judges designated to preside at such hearing, or, if no Commissioner or administrative law judge is yet designated, the Chief Administrative Law Judge; and (2) when used with respect to any other proceeding, means any employee (including the Oil Pipeline Board) designated by rule or order to conduct that proceeding.

(e) "Respondent" means (1) a person to whom an order to show cause or notice of tariff or rate examination is issued by the Commission, (2) a person against whom a complaint is directed, or (3) a person designated as a respondent by the Commission or by other provisions of this chapter.

§ 385.103 Reference to, and citation of, rules. (Rule 103.)

This part is referred to as the "Rules of Practice and Procedure." Each section of Part 385 is referred to as a "Rule." The number of each rule includes only the numbers at the right of the decimal point in the section designation. For example, "§ 385.103 *References to, and citation of, rules.*" is referred to as "Rule 103."

Subpart B—Pleadings, Tariff or Rate Filings, Notices of Tariff or Rate Examination, Orders To Show Cause, Intervention and Summary Disposition

§ 385.201 Applicability. (Rule 201.)

This subpart contains the requirements for pleadings, tariff or rate filings, notices of tariff or rate examination, orders to show cause, interventions, and summary dispositions.

§ 385.202 Types of pleadings. (Rule 202.)

Pleadings include applications, complaints, petitions, protests, notices of protest, answers, motions and amendments or withdrawals thereof.

§ 385.203 Content of pleadings and tariff or rate filings. (Rule 203.)

(a) *Requirements for all pleadings or tariff or rate filings.* Each pleading or tariff filing must include, if appropriate:

(1) If known, the reference numbers, docket numbers, or other identifying symbols of any relevant tariff, rate, schedule, contract, application, rule, or similar matters or material;

(2) The name of each participant on behalf of whom the pleading or tariff filing is made;

(3) The specific authorization or relief sought;

(4) The tariff sheets;

(5) If not previously set forth, the relevant facts;

(6) To the extent known when a pleading is filed, the position taken by the participant filing such pleading, and the basis in fact and law for such position;

(7) Subscription or verification, if required;

(8) A certificate of service under Rule 2010(h), if service is required;

(9) The name, address, and telephone number of an individual who, with respect to any matter contained in the filing, represents the person on behalf of whom the filing is made; and

(10) All other information required to be included by statute or Commission rule or order.

(b) *Combined pleadings.* If two or more pleadings are included in a single filing, each pleading must be separately designated and must conform to the requirements applicable to such pleading.

(c) *Requirements for first pleadings or tariff or rate filings.* In addition to the requirements in paragraph (a) of this section, the first pleading or tariff or rate filing filed by a participant or by a person who is seeking to become a party must include:

(1) The exact legal name of the person on whose behalf the filing is made;

(2) The location of that person's principal place of business; and

(3) The name and address of at least one, but not more than two, persons upon whom service is to be made and to whom communications are to be addressed in the proceeding.

§ 385.204 Applications. (Rule 204.)

A person must file an application to obtain a license, permit, certification, or similar authorization or permission.

§ 385.205 Tariff or rate filings. (Rule 205.)

A person must make a tariff or rate schedule filing to establish or change a specific rate, rate schedule, tariff, tariff schedule, fare, charge, or term, condition of service, classification, contract,

practice, or an applicant's regulation, related thereto.

§ 385.206 Complaints. (Rule 206.)

(a) *General rule.* A person may file a complaint to seek Commission action against another person alleged to be in contravention or violation of any statute, rule, order, or other authority administered by the Commission, or for any other alleged wrong over which the Commission may have jurisdiction.

(b) *Content.* In addition to the requirements of Rule 203 (content), a complaint must include the name and address of each person against whom it is directed.

(c) *Answers.* The person against whom a complaint is directed must respond to such complaint by filing an answer.

(d) *Satisfaction.* (1) If the respondent to a complaint satisfies such complaint, in whole or in part, either before or after an answer is filed, the complainant and the respondent must sign and file:

(i) A statement setting forth when and how the complaint was satisfied; and

(ii) A motion for dismissal of, or an amendment to, the complaint based on the satisfaction.

(2) The decisional authority may order the submission of additional information before acting on a motion for dismissal or an amendment under paragraph (d)(1)(ii) of this section.

§ 385.207 Petitions. (Rule 207.)

(a) *General rule.* A person must file a petition to seek Commission action:

(1) Granting relief under Subparts I, J and K;

(2) Issuing a declaratory order or rule to terminate a controversy or remove uncertainty;

(3) Granting relief from a staff action (other than a decision or ruling of a presiding administrative law judge) taken pursuant to authority delegated under this part or otherwise that would be final but for this section; or

(4) Taking other action which is in the discretion of the Commission and for which this chapter prescribes no other form of pleading.

(b) *Declarations of intent under the Federal Power Act.* For purposes of this part, a declaration of intent under section 23(b) of the Federal Power Act is treated as a petition for a declaratory order.

§ 385.208 Notices of protest to tentative oil pipeline valuations. (Rule 208.)

(a) *General rule.* A person who objects to a tentative valuation of an oil pipeline under section 19a of the Interstate Commerce Act (49 U.S.C. 19a(i)) must file the notice of protest required under that section. A notice of protest has the effect prescribed in section 19a of the Interstate Commerce Act (49 U.C.S. 19a).

(b) *Service.* A notice of protest must be served by the protestant on the oil pipeline whose tentative valuation is protested.

§ 385.209 Notices of tariff or rate examination and orders to show cause. (Rule 209.)

(a) *Issuance.* (1) When the Commission seeks to determine the validity of a rate, charge, or classification demanded, observed, charged, or collected, the Commission may initiate a proceeding by issuing a notice of tariff or rate examination.

(2) The Commission may initiate a proceeding against a person by issuing an order to show cause.

(b) *Contents.* The notice or order will contain a statement of the matters about which the Commission is inquiring, and a statement of the Commission's authority under which it is acting. The statement is tentative and for the purposes of framing issues for consideration and decision by the Commission.

(c) *Answers.* A person against whom an order to show cause is directed must answer in accordance with Rule 213 (answers).

§ 385.210 Notice. (Rule 210.)

When appropriate, the Secretary will cause notices of tariff or rate filings, applications, petitions, notices of tariff or rate examinations, and orders to show cause, to be made in accordance

with Rule 2009 (notice). The notice will establish the dates for filing interventions and protests.

§ 385.211 Other protests. (Rule 211.)

(a) *General rule.* A person may file a protest who objects to an application, complaint, petition, order to show cause, notice of tariff or rate examination, or tariff or rate filing. The filing of a protest does not make the protestant a party to the proceeding. The protestant must intervene to become a party. The Commission will consider protests in determining further appropriate action. The protest will be placed in the public file associated with the proceeding, but, if a hearing is set, the protest is not part of the record upon which the decision is made.

(b) *Service.* Each protest directed against a person in a proceeding must be served by the protestant on the person against whom the protest is directed. The Secretary may waive the procedural requirements of this subpart applicable to protests; however, if the requirement of service is waived, the Secretary will place the protest in the public file and may send a copy thereof to the person against whom the protest is directed.

§ 385.212 Motions. (Rule 212.)

(a) *General rule.* Unless otherwise specifically provided, a motion may be filed at any time by a participant or by a person who has filed a motion to intervene which has not been denied.

(b) *Oral motions.* A motion must be in writing, except that the presiding officer may permit an oral motion to be made on the record during the course of a hearing or conference.

(c) *Contents.* A motion must contain a clear and concise statement of the facts and law which support the motion and of the specific relief or ruling desired.

(d) *Motions to the Commission.* The Commission will designate a member of the Commission as the motions Commissioner who will rule on motions made to the Commission (other than a motion for summary disposition or interlocutory appeal). The motion is deemed denied at the end of 30 days, unless the motion is acted upon within such period. Such Commissioner will also serve as the motions Commissioner under Rule 715 (rulings on interlocutory appeals). For purposes of this paragraph, a motion made to a subordinate official of the Commission is not considered as having been made to the Commission.

§ 385.213 Answers. (Rule 213.)

(a) *Required or permitted.* (1) An answer must be made by a respondent to a complaint or order to show cause, unless the Commission orders othewise.

(2) An answer may not be made to a protest, an answer, a motion for oral argument, or a request for rehearing, unless otherwise ordered by the decisional authority.

(3) An answer may be made to any pleading or motion not prohibited by paragraph (a)(2) of this section, except that the presiding officer may prohibit the filing of an answer to a motion for interlocutory appeal.

(4) An answer to a notice of tariff or rate examination must be made in accordance with the provisions of such notice.

(b) *Oral answers.* An answer must be in writing, except that the pleading officer may permit an oral answer to a motion made on the record in the course of a hearing or conference.

(c) *Contents.*—(1) *General answers.* An answer must contain a clear and concise statement of the disputed factual allegations and any law upon which the answerer relies. If an answer is made in response to a complaint or order to show cause, or an amendment thereto, the answerer must, to the extent practicable, admit or deny specifically and in detail each material allegation of the pleading answered, and must set forth every defense relied upon.

(2) *Answers to orders to show cause.* Mere general denials of facts referred to in an order to show cause unsupported by specific facts upon which the respondent relies will not be considered as complying with paragraph (a)(1) of this section and may be a basis for summary disposition without hearing.

unless otherwise required by statute, on the ground that the respondent has raised no issues requiring a hearing or further proceedings.

(d) *Time limitations.* (1) An answer to a motion or amendment thereto must be made within 15 days after the motion or amendment is filed, unless otherwise ordered.

(2) An answer to a pleading or amendment thereto, other than an answer to a motion under paragraph (d)(1) of this section, must be made within 30 days after publication in the Federal Register notice of such pleading or amendment, unless otherwise ordered. In the absence of Federal Register publication, an answer under this paragraph must be made within 30 days after the pleading or amendment thereto was filed, unless otherwise ordered.

(e) *Failure to answer.* A person failing to answer a complaint may be considered to be in default, and all relevant facts stated in such complaint may be deemed admitted. Failure to answer an order to show cause will be treated as a general denial to which paragraph (c)(2) of this section applies.

§ 385.214 Intervention. (Rule 214.)

(a) *Filing.* (1) The Secretary of Energy becomes a party to a proceeding upon filing a notice of intervention. If the notice is not filed within the period prescribed under Rule 210 (notice), the notice must state the position of the Secretary on the issues in the proceeding.

(2) A State Commission becomes a party to a proceeding upon filing a notice of intervention, but only if such notice is filed within the period prescribed under Rule 210 (notice). After the expiration of such period, a State Commission must comply with the rules for motions to intervene applicable to a person to whom paragraph (a)(3) of this section applies, including the content requirements of paragraph (c) of this section.

(3) Any person, other than the Secretary of Energy or State Commission, who seeks to become a party must file a motion to intervene.

(b) *Contents of motion.* (1) A motion to intervene must state, to the extent known, the position taken by the movant and the basis in fact and law for such position and must state the movant's interest in sufficient factual detail to demonstrate that:

(i) The movant has a right to participate which is expressly conferred by statute or Commission, rule, order or other action;

(ii) The movant represents an interest as to which the movant may be directly affected by the outcome (which may include a movant's interest as a consumer, customer, competitor, or security holder of a party, or customer served by a party); or

(iii) The movant's participation is in the public interest.

(2) In addition to the requirements of paragraph (b)(1) of this section, a motion to intervene which is not filed within the period prescribed under Rule 210 (notice) must state the position of the movant, if know, on the issues in the proceeding and show good cause why the time limitation should be waived.

(c) *Grant of party status.* (1) If no answer in opposition to a motion to intervene is filed within 15 days after the motion to intervene is filed, the movant becomes a party at the end of the 15 days.

(2) If an answer in opposition to a motion to intervene is filed within 15 days after the motion to intervene is filed. The movant becomes a party only when the motion is expressly granted.

(d) *Grant of late intervention.* (1) In acting upon a motion to intervene filed after the period prescribed under Rule 210 (notice), the decisional authority may consider whether the movant has shown good cause for failing to file within the time prescribed, the disruption of the proceeding, and the prejudice to, or additional burdens upon, the existing parties which might be caused if the intervention is permitted.

(2) Except to the extent otherwise ordered, the grant of intervention shall not be the basis for delaying or deferring any procedural schedule established prior to such movant's intervention.

(3)(i) The decisional authority may impose limitations on the participation of late a intervener to avoid delay and prejudice to the other participants.

(ii) Except to the extent otherwise ordered, an intervener is required to accept the record of the proceeding as it was developed prior to such movant's intervention.

(4) If the presiding officer grants a motion for late intervention orally, he will promptly issue a written order confirming the oral order.

§ 385.215 Amendment of pleadings. (Rule 215.)

(a) *General rules.* (1) A participant or a person who is seeking to become a party may seek to modify its pleading by filing an amendment which conforms to the requirements applicable to the pleading to be amended.

(2) A tariff or rate filing may not be amended except pursuant to statutory authority.

(3) A written amendment filed before the fifth day before the earlier of the first prehearing conference or the first day of evidentiary hearings becomes effective as of right on the date filed. A written amendment filed after that date, or an oral amendment made to a presiding officer during the course of a hearing or conference, becomes effective only in accordance with paragraph (d) of this section.

(b) *Answers.* A participant may answer an amendment on the merits in accordance with Rule 212 of this part (answers).

(c) *Motion opposing the filing of an amendment.* A participant, or a person who has filed a motion to intervene under Rule 214 (intervention) which has not been denied, may file a motion opposing the filing of an amendment, other than an amendment effective as of right under paragraph (a)(2) of this section, within 15 days of filing of the amendment.

(d) *Acceptance of amendments.* If no motion in opposition to the acceptance of an amendment which does not become effective as of right is filed within 15 days after the amendment is filed, the amendment becomes effective at the end of the 15 day period. If a motion in opposition to the acceptance of such an amendment is filed within such period, the amendment becomes effective at the end of the 15 day period, unless the decisional authority, before such date, issues an order rejecting the amendment, in whole or in part, for good cause.

(e) *Directed amendments.* The decisional authority, on motion or otherwise, may direct a participant or person who is seeking to become a party to file an amendment to amplify, clarify, or technically correct a pleading in writing.

§ 385.216 Withdrawal of pleadings. (Rule 216.)

(a) *Filing.* A participant may seek to withdraw a pleading by filng a notice of withdrawal.

(b) *Action on withdrawals.* When no motion in opposition is filed within 15 days, the withdrawal becomes effective at the end of that period, unless, within that period, the decisional authority issues an order disallowing the withdrawal. When a motion in opposition is filed, the withdrawal is not effective until the decisional authority issues an order accepting the withdrawal. An order under this paragraph may disalllow all or part of a withdrawal for good cause.

(c) *Conditional withdrawal.* To prevent prejudice to other participants, the decisional authority, on motion or otherwise, may condition the withdrawal upon a requirement that the withdrawing party leave material in the record or otherwise make material available to other participants.

§ 385.217 Summary disposition. (Rule 217.)

(a) *General rule.* If the decisional authority determines that there is no genuine issue of fact material to the decision of a proceeding or a part thereof, the decisional authority may summarily dispose of all or part of the proceeding.

(b) *Procedures.* (1) A participant may make a motion for summary disposition of all or part of a proceeding.

(2) When a decisional authority, other than the Commission, is considering summary disposition in the absence of a motion by a participant, the decisional authority must grant the participants an opportunity to comment on the proposed disposition prior to summary disposition, unless for good cause shown the decisional authority otherwise provides.

(3) When the Commission is considering ordering summary disposition in the absence of a motion by a participant and prior to setting a matter for hearing, and if it determines that notice and comment procedures are practicable and necessary, it may notify the participants and afford them an opportunity to comment on the proposed disposition.

(c) *Disposition.* (1) (i) When a decisional authority, other than the Commission, summarily disposes of all of a proceeding, the decisional authority will issue an initial decision in the entire proceeding.

(ii) Except as provided in paragraph (c)(1)(iii) of this section, when summary disposition is made of part of a proceeding, the decisional authority may issue a partial initial decision or may postpone issuing an initial decision on such part and combine it with the initial decision on the entire or appropriate part of the proceeding.

(iii) When summary disposition is made of part of a proceeding and such disposition requires the filing of new tariff or rate schedule sheets, the decisional authority will issue an initial decision disposing of that part of the proceeding.

(2) A decision issued under paragraph (c)(1) of this section shall be treated as an initial decision issued under Subpart G of this part, except that Rules 704, 705, 706, 707, and 709 of this part do not apply (rights of participants before initial decision discretion of presiding officer before initial decision, initial and replied briefs before initial decision, oral argument before initial decision, and other types of decisions).

Subpart C—[Reserved]

Subpart D—[Reserved]

Subpart E—Hearings

§ 385.501 Applicability. (Rule 501.)

This subpart applies to a proceeding or part of a proceeding which the Commission sets for a hearing to be conducted in accordance with this subpart.

§ 385.502 Initiation of hearing. (Rule 502.)

(a) *Notice or order initiating hearing.* A hearing under this subpart will be initiated:

(1) By the Commission by issuance of an order, or

(2) By notice of the Secretary at direction of the Commission, or

(3) By order of the Oil Pipeline Board.

(b) *Contents of notice or order initiating hearing.* The order or notice under paragraph (a) of this section shall set forth:

(1) The authority and jurisdiction under which the hearing is to be held;

(2) The nature of the proceeding;

(3) The final date for the filing of protests and interventions, where the dates were not fixed by an earlier notice;

(4) The presiding officer, if one has been designated; and

(5) The date, time, and location of the hearing or prehearing conference, if known; and

(6) Any other appropriate matter.

(c) *Consolidation, severance, and phasing.* The notice or order may direct consolidation of proceedings, phasing of a proceeding, or severance of proceedings or issues in a proceeding.

§ 385.503 Consolidation and severance by chief administrative law judge. (Rule 503.)

The Chief Administrative Law Judge may, upon motion or otherwise, order proceedings pending under this subpart

consolidated for hearing on any or all matters in issue in such proceedings, or order the severance of proceedings, or issues in a proceeding.

§ 385.504 Duties and powers of presiding officers. (Rule 504.)

(a) *Duties.*—(1) *Conduct of fair and impartial hearing.* It shall be the duty of the presiding officer to conduct a fair and impartial hearing, and to determine the matter justly under the law.

(2) *Appearances.* The presiding officer before whom a hearing is held shall cause all appearances to be entered on the record with a notation in whose behalf each appearance is made.

(3) *Order of presentation.* The presiding officer shall prescribe the order of presentation of the cases of all participants in the hearing.

(4) *Requirement for diligence and lack of delay.* The presiding officer shall assure that the taking of evidence and subsequent matters proceed with all reasonable diligence and with the least practicable delay.

(5) *Initial decision.* The presiding officer shall prepare and certify an initial decision to the Commission, as provided in Subpart G of this chapter.

(b) *Powers.* Except as ordered otherwise by the Commission, the presiding officer may exercise the following powers:

(1) *Scheduling.* Scheduling and otherwise regulating the course of the hearing.

(2) *Recessing, reconvening, postponing, adjourning.* Recessing, reconvening, postponing, or adjourning the hearing.

(3) *Oaths and affirmations.* Administering oaths and affirmations.

(4) *Evidence.* Ruling on and receiving evidence.

(5) *Taking of discovery.* Taking or causing discovery to be conducted.

(6) *Subpoenas.* Issuing subpoenas under Subpart D.

(7) *Conferences.* Holding conferences of the participants, as provided in Subpart F of this chapter.

(8) *Disposition of procedural matters.* Ruling on and disposing of procedural matters, including oral or written motions.

(9) *Summary disposition.* Summarily disposing of a proceeding or part thereof as provided in Rule 217 (summary disposition).

(10) *Certifying questions.* Certifying a question to the Commission as provided in Rule 714 (certified questions).

(11) *Appeal of interlocutory ruling.* Permitting appeal of an interlocutory ruling, as provided in Rule 715 (interlocutory appeals).

(12) *Intervention.* Ruling on motions to intervene as provided in Rule 214 (intervention).

(13) *Phasing.* Separating a particular issue or issues in a proceeding from others, and treating such issue or issues as a separate phase of the proceeding.

(14) *Maintaining order.* Any disregard by any person of rulings on matters of order and procedure shall be noted on the record, and may be made the subject of a special written report to the Commission. In the event a person engages in disrespectful, disorderly, or contumacious language or conduct in connection with a hearing, the presiding officer may recess the hearing for such time as is necessary to regain order. The presiding officer may request that the Commission take appropriate action, including removal, against a participant or counsel if necessary to maintain order.

(15) *Modifying time period.* Modifying any time period if such modification is in the interest of justice and will result in no undue prejudice to any participant.

(16) *Number of expert witnesses.* Limiting the number of expert witnesses who may testify on any issue consistent with the rule against repetitious testimony in Rule 905(a).

(17) *Number of persons representing a similar interest.* Limiting the number of persons (other than staff) representing a similar interest who may examine, make and argue motions and objections.

(18) *Further evidence.* Requiring, or authorizing the admission of, further evidence upon any issue at any time

before the close of the evidentiary record.

(19) *General authority.* Taking any other action necessary or appropriate to the discharge of the duties vested in him, consistent with applicable law and policy.

(c) *Disqualification.* A presiding officer who believes himself disqualified may withdraw from a proceeding. The Commission may order the removal of a presiding officer for good cause either upon motion filed with the Commission or otherwise.

§ 385.505 Right of participants to present evidence. (Rule 505.)

Participants have the right to present such evidence, including rebuttal evidence, and to conduct such cross-examination as may be necessary to assure the true and full disclosure of facts.

§ 385.506 Examination of witnesses. (Rule 506.)

(a) *General rule.* Except as provided in paragraphs (b), (c), or (d) of this section, examination of a witness must be conducted orally under oath in the presence of the presiding officer with the opportunity for all participants to question the witness.

(b) *Prepared written direct testimony and prepared written rebuttal testimony.* Unless otherwise ordered by the presiding officer, direct and rebuttal testimony must be prepared in written form and comply with the requirements of Rule 507 of this part (relating to prepared testimony). Prepared testimony will be treated as an exhibit and the witness sponsoring the exhibit must be made available for oral cross-examination. The cross-examination must be conducted in accordance with the other provisions of this section.

[THIS PARAGRAPH IS NOT A PROPOSED RULE, BUT IS HERE FOR DISCUSSION ONLY]

[(c) *Oral testimony not conducted in the presence of the presiding officer.* The presiding officer need not be present at the examination of a witness: *Provided,* That:

(1) The presiding officer issues and order finding that (i) the participants agree that the examination may be so conducted, or (ii) the presiding officer finds good cause for such examination;

(2) The participants are notified in advance of the examination of the witness and the time and place of their examination;

(3) The participants are afforded the opportunity to put questions to the witness; and

(4) The participants are advised that this opportunity to put questions to the witness as provided in paragraph (c) of this section may be in lieu of the opportunity to put questions to the witness in the presence of the presiding officer.]

[THIS PARAGRAPH IS NOT A PROPOSED RULE, BUT IS HERE FOR DISCUSSION ONLY]

[(d) *Written cross-examination of witnesses.* The presiding officer may, with the consent of the participants, permit the use of prepared written cross-examination which complies with Rule 507 (prepared written testimony). The testimony may be based on interrogatories or other discovery. Prepared written cross-examination will be treated as an exhibit. When written cross-examination under this paragraph is used, a participant may, by written motion, request that such examination be supplemented by oral cross-examination. The presiding officer may grant such a motion only if the motion establishes that such supplemental oral cross-examination is necessary.]

§ 385.507 Prepared written testimony. (Rule 507.)

(a) *To be an exhibit.* Prepared written testimony of any witness must be offered as an exhibit. When prepared written testimony is required by the presiding officer, a reasonable period of

time will be allowed for the preparation of such written testimony.

(b) *Time for filing.* All prepared written testimony must be served within the time provided by the presiding officer, but at least 10 days in advance of the session of the hearing at which such exhibit is offered, unless a shortened time is permitted under paragraph (c) of this section.

(c) *Late-filed testimony.* The participants in attendance at the hearing may agree unanimously that all or any part of such 10 days' prior service be waived. The presiding officer, absent such agreement, will permit the introduction of prepared written testimony if necessary for a full disclosure of the facts or may permit upon any other showing of good cause unless unduly prejudicial to any participant. Where such testimony is served within the 10 day period the presiding officer will give the participants present a reasonable opportunity to examine it.

(d) *Forms.* Prepared written testimony must have line numbers inserted on each page, in the left-hand margin, and must be authenticated by an affidavit of the witness.

§ 385.508 Exhibits. (Rule 508.)

(a) *General rule.* Except as provided in paragraphs (b) through (e) of this section, material offered in evidence except oral testimony must be offered in the form of an exhibit. A participant who seeks to have an exhibit admitted into evidence must provide one copy of the exhibit to the presiding officer and two copies to the reporter at the time the participant moves for its admission. The presiding officer will mark for identification every exhibit offered by a participant.

(b) *Designation of matter sought to be admitted.* When a document offered as an exhibit contains material not offered as evidence, the participant offering the exhibit must plainly designate the matter offered as evidence, and must so segregate and exclude insofar as is practicable the material not so offered. If the matter not offered is so extensive as to unnecessarily encumber the record, such document will not be received in evidence but may be marked for identification. If properly authenticated, the material offered as evidence may be read into the record, or if the presiding officer so directs, a true copy of such material in proper form will be received in evidence as an exhibit. Copies of the exhibit must be delivered by the participant offering the same to the other participants appearing at the hearing who will be offered an opportunity to examine the entire document to offer in evidence in like manner other portions thereof.

(c) *Public document item by reference.* Whenever part or all of a public document is offered in evidence and the offerer shows that the document, or part thereof, is reasonably available to the public, such document need not be produced or marked for identification, but may be offered in evidence as a public document item by reference by specifying the document or relevant part thereof.

(d) *Official notice of facts.* Official notice may be taken by the presiding officer of such matters as might be judicially noticed by the courts of the United States, or any matters as to which the Commission by reason of its functions is an expert. A participant must, on timely request, be afforded an opportunity to show the contrary. A participant requesting the taking of official notice after the conclusion of the hearing must set forth the reasons claimed to justify failure to make the request prior to the close of the hearing.

(e) *Stipulations.* Participants may stipulate as to any relevant matters of fact or the authenticity of any relevant documents. The stipulations may be received in evidence at the hearing, and when so received, are binding on the stipulating participants with respect to the matters therein stipulated. A stipulation may be made orally at the hearing or in written form.

§ 385.509 Admissibility of evidence. (Rule 509.)

(a) *General standard.* The presiding officer should exclude from evidence irrelevant, immaterial and unduly repetitious material. The presiding officer may exclude from evidence any other material he determines is not of the kind which would affect reasonable and fairminded persons in the conduct of their daily affairs.

(b) *Ruling on evidence.* The presiding officer will rule on the admissibility of all evidence offered. When an objection is made to the admission or exclusion of evidence, the grounds for the objection will be stated briefly. Formal exceptions are not permitted, but this does not preclude the arguing of the validity of a ruling on evidence at a later time in such proceeding.

§ 385.510 Miscellanous provisions. (Rule 510.)

(a) *Transcript.* (1) Every statement made at a hearing session will be transcribed in a verbatim report from which nothing will be omitted except as directed on the record by the presiding officer. Statements at a hearing must not occur off-the-record, except as directed by the presiding officer.

(2) After the closing of the record, there will be no changes in the transcript, except as provided in paragraph (b) of this section.

(b) *Transcript corrections.* Corrections in the official transcript may be made only to make it conform to the evidence presented at the hearing and to speak the truth. Transcript corrections agreed to by opposing participants may be incorporated into the record, when approved by the presiding officer, at any time during the hearing or after the close of evidence, as may be permitted by the presiding officer before the filing of the initial decision but not less than 10 days in advance of the time fixed for filing final briefs. The presiding officer may call for the submission of proposed corrections and will rule upon proposed corrections during the proceeding.

(c) *Close of evidentiary record.* The presiding officer will designate the time at which the evidentiary record is closed. Thereafter no evidence will be added to the evidentiary record unless the record is reopened under Rule 716 (reopening).

(d) *Copies of exhibits and motions to participants.* Except as otherwise provided in this subpart, copies of exhibits and motions will be furnished at the hearing to the presiding officer and to the participants.

(e) *Fees of witnesses.* Witnesses subpoenaed by the Commission will be paid the same fees and mileage as are paid for like services in the district court of the United States. Witnesses subpoenaed at the instance of participants will be paid the same fees and mileage by the participant at whose instance the witness is subpoenaed. The Commission, before issuing any subpoena, may require a deposit of an amount adequate to cover the fees and mileage involved.

(f) *Offers of proof.* An offer of proof, made in connection with a ruling of the presiding officer rejecting or excluding proffered oral testimony, will consist of a statement of the substance of the evidence which participant claims would be adduced by the testimony. If the excluded evidence is in the form of an exhibit or is a public document, a copy of such exhibit will constitute the offer of proof of the public document will be specified by identification.

Subpart F—Conferences, Settlements, and Stipulations

§ 385.601 Conferences (Rule 601.)

(a) *When convened.* Upon motion or otherwise, the Commission or the decisional authority in a proceeding may convene a conference of the participants in the proceeding at any time.

(b) *Purpose.* A conference may be convened for any purpose related to the conduct or disposition of a proceeding, including submission and consideration of offers of settlement.

(c) *General requirements.* Due notice of the time and place of a conference and of the matters to be addressed at

the conference must be given to the participants. Participants attending a conference must be prepared to discuss the matters to be addressed at the conference, unless there is good cause for a failure to be prepared. A person appearing in a representative capacity must be authorized to act on behalf of such person's principal with respect to such matters. Failure of a party to attend such a conference will constitute a waiver of all objections to the agreements reached, if any, and any order or ruling arising out of such conference.

(d) *Powers of decisional authority at conference.* The decisional authority before whom the conference is held, or to whom it reports, may dispose of any procedural matters upon which he is authorized to rule during the course of the proceeding, and which it appears may appropriately and usefully be disposed of at that stage. In addition, in the case of a proceeding set for hearing under Subpart E, where it appears that the proceeding would be substantially expedited by distribution of proposed exhibits, written prepared testimony, and other documents reasonably in advance of the hearing session, the presiding officer, with due regard for the convenience of the participants, may direct advance distribution by a prescribed date. The presiding officer may also direct the preparation and distribution of briefs and other documents as he determines will substantially expedite the proceeding.

§ 385.602 Submission of settlement offers. (Rule 602.)

(a) *Applicability.*—(1) *General rule.* This section applies to written offers of settlement filed in any proceeding to which this subpart applies. For purposes of this section, the term "offer of settlement" includes any written proposal to modify an offer of settlement.

(2) *Oil pipeline proceedings.* In the case of any proceeding under the Interstate Commerce Act, the functions of the Commission with respect to review and approval of offers of settlement under this section are vested in the Oil Pipeline Board. Action of the Board are reviewable by the Commission under section 17 of the Interstate Commerce Act.

(b) *Submission of offer.* A participant in a proceeding may submit an offer of settlement at any time. An offer of settlement must be filed with the Secretary of the Commission. The Secretary will transmit the offer to the presiding officer if the offer is filed after a hearing has been ordered and before the time the presiding officer certifies the record to the Commission. In any other case, the Secretary will transmit the offer of settlement to the Commission.

(c) *Contents of offer.* (1) An offer of settlement must include a document embodying the settlement offer, an explanatory statement, copies of or references to (including record citations if there is a record) such documents, testimony, exhibits, or other matters, which the offerer considers relevant to the offer of settlement. An offer of settlement must also include a proposed order of the Commission approving the settlement, which order must include the following provision:

> The Commission's approval of this settlement shall not constitute approval of or precedent regarding any principle or issue in this proceeding.

(2) If the offer of settlement relates to a tariff filing, the offer must include proposed tariff changes in a form suitable for inclusion in the filed rate schedules or tariffs, together with a sufficient number of copies to satisfy the filing requirements applicable to tariff filings of the type at issue in the proceeding.

(d) *Service.* A copy of the offer of settlement must be served on participants in accordance with Rule 2010 (service) and on the persons who are required by the Commission's rules to be served with the pleading or tariff or rate filing with respect to which the proceeding was initiated. The participant serving the offer of settlement must notify the persons

served of the date comments on the settlement are due under paragraph (f) of this section.

(e) *Use of non-approved offers of settlement as evidence.* Offers of settlement which are not approved by the Commission, and comments thereon, will not be admissible in evidence against any participant objecting to their admission. Discussion of the parties with respect to an offer of settlement not approved by the Commission will not be subject to discovery or admissible in evidence.

(f) *Comments.* Comments on an offer of settlement will be filed with the Secretary who will transmit them to the Commission if the offer was transmitted to the Commission, or to the presiding officer in any other case. Comments may be filed on or before 20 days after the filing of the offer of settlement and reply comments may be filed on or before 30 days after the filing of such offer, unless otherwise provided for by the Commission or the presiding officer. Failure to file comments constitutes a waiver of all objections to the offer of settlement.

(g) *Uncontested offers of settlement.* If comments on an offer were transmitted to the presiding officer and such officer finds that the offer is not contested by any participant, the presiding officer will certify to the Commission the offer of settlement, a statement that the offer of settlement is uncontested, and any hearing record or pleadings which relate to the the offer of settlement. If comments on an offer of settlement were transmitted to the Commission, the Commission will determine whether the offer is uncontested. An uncontested offer of settlement may be approved by the Commission upon a finding that the settlement appears to be fair and reasonable and in the public interest.

(h) *Contested offers of settlement.* (1) If the Commission determines the offer of settlement is contested by any party, in whole or in part, the Commission may reach a decision on the merits of the contested settlement issues if the record contains substantial evidence upon which to base a reasoned decision or if the Commission determines there is no contested issue of material fact. If the Commission finds that the record is lacking in substantial evidence or that the contested issues cannot be severed from the offer of settlement, the Commission will establish procedures before a presiding officer for the purpose of receiving additional evidence upon which a decision on the contested issues can reasonably be based or take such other action as it determines to be appropriate. When contested issues are severable, the uncontested portions may be severed and decided in accordance with paragraph (g) of this section.

(2) If comments on an offer of settlement are transmitted to the presiding officer and such officer determines that the offer is contested, in whole or in part, by any participant, the officer may certify all or part of such offer to the Commission. An offer or part thereof contested by a party may be certified only if:

(i) Either (A) the presiding officer determines that there is no contested issue of material fact, or (B) the parties concur on a motion for omission of the initial decision as provided in Rule 710 (waiver of the initial decision);

(ii) The presiding officer determines that the record contains substantial evidence from which the Commission may reach a reasoned decision on the merits of the contested issues, and

(iii) The parties have had an opportunity to avail themselves of such rights as they may with respect to the opportunity to present evidence and cross-examine opposing witnesses. When the contested issues are severable, the uncontested portions of the settlement may be certified immediately to the Commission for decision as provided in paragraph (g) of this section.

(i) *Reservation of rights.* The procedural rights a participant would have in the absence of an offer of settlement are not affected if the Commission does not approve, or approves subject to condition, the unopposed portion of the offer of settlement.

§ 385.603 Settlement negotiations before a settlement judge. (Rule 603.)

(a) *Applicability.* This section applies to a proceeding set for hearing under Subpart E.

(b) *Definitions.* For purposes of this section, "settlement judge" means the administrative law judge appointed by the Chief Administrative Law Judge to conduct settlement negotiations under this section.

(c) *Requests for appointment of settlement judges.* (1) A participant may file a motion for the appointment of a settlement judge. The motion must be made with the presiding officer, or, if the motion is made when there is no presiding officer for the proceeding, with the Commission.

(2) A presiding officer may request the Chief Administrative Law Judge to appoint a settlement judge.

(3) Notwithstanding the provisions of Rule 213(c) of this part (time limitations on answers), a motion under paragraph (a) of this section may be acted upon at any time. Answers or objections filed after a motion has been acted upon will not be considered.

(d) *Commission order directing appointment of settlement judge.* The Commission may by order, on motion or otherwise, direct the Chief Administrative Law Judge to appoint a settlement judge.

(e) *Appointment of settlement judge by Chief Administrative Law Judge.* The chief administrative law judge may appoint a settlement judge for a proceeding if requested by the presiding officer under paragraph (c)(2) of this section, or if the presiding officer concurs in a motion under paragraph (c)(1) of this section.

(f) *Order appointing settlement judge.* The appointment of a settlement judge will be by order of the Chief Administrative Law Judge. The order will specify whether and to what extent the proceeding is suspended pending termination of settlement negotiations conducted in accordance with this section. The order may confine the scope of such settlement negotiations to specified issues.

(g) *Powers and duties of settlement judge.* (1) The settlement judge will call and preside over conferences and settlement negotiations of the participants and assess the practicalities of a potential settlement.

(2) The settlement judge will submit a report to the Chief Administrative Law Judge or Commission, as appropriate, of the status of the settlement negotiations and an evaluation as to settlement prospects. The settlement judge may make recommendations as to the continuation of the settlement negotiations conducted under this section. The first report will be made no later than 30 days following the appointment of the settlement judge. The Commission or the Chief Administrative Law Judge may order additional reports at any time.

(h) *Termination of settlement negotiations before a settlement judge.* Unless an order of the Commission directing the appointment of a settlement judge provides otherwise, settlement negotiations conducted under this section will terminate upon the order of the Chief Administrative Law Judge issued after consultation with the settlement judge.

(i) *Non-reviewability.* Any decision concerning the appointment of a settlement judge or termination of settlement negotiations is not subject to review by, appeal to, or rehearing by the presiding judge, Chief Administrative Law Judge, or the Commission.

(j) *Multiple settlement negotiations.* If settlement negotiations are terminated under paragraph (h) of this section, the Chief Administrative Law Judge may subsequently appoint a settlement judge in the same proceeding to conduct settlement negotiations in accordance with this section.

§ 385.604 Refusal to make admissions or stipulations. (Rule 604.)

If a party in a proceeding set for hearing under Subpart E refuses to admit or stipulate to the genuineness of a document or the truth of a matter of fact and if the party requesting the

admission or stipulation thereafter proves the genuineness of document or the truth of matter of fact, the party who made the proof may apply to the presiding officer for an order requiring the other party to pay the reasonable expenses incurred in making the proof, including reasonable attorney's fees. Unless the officer finds that there was good reason for the refusal to admit or stipulate or that the admission or stipulation sought were of no substantial importance, the order shall be made. An appeal from the order may be taken to the Commission immediately. If a party refuses to comply with the order after it becomes final, the Commission may strike all or any part of the party's pleadings or limit or deny further participation by the party. Proposed stipulations not agreed to are not admissible in evidence against any participant objecting to the admission.

Subpart G—Decisions

§ 385.701 Applicability. (Rule 701.)

This subpart applies to decisions in proceedings set for hearing under Subpart E of this part, including a decision on a certified question, interlocutory appeal, or reopening, and to a decision on rehearing, except that:

(a) The provisions of this subpart (other than those relating to rehearing or reopening) are inapplicable to consideration of an offer of settlement, and

(b) This subpart applies to summary disposition only to the extent provided in Rule 217 (summary disposition).

§ 385.702 Definitions. (Rule 702.)

For purposes of this subpart:

(a) "Initial decision" is a decision rendered in accordance with Rule 708 (initial decisions by presiding officers).

(b) "Final decision" is a decision referred to in Rule 713 (requests for rehearing of final decisions).

§ 385.703 Contents of decisions. (Rule 703.)

Each decision will become a part of the record in the proceeding and will contain:

(a) A ruling on each exception presented and findings and conclusions, with supporting reasons, upon all material issues of fact, law, or matters of discretion presented on the record, and

(b) The appropriate rule, order, sanction, relief, or denial thereof.

§ 385.704 Rights of participants before initial decision. (Rule 704.)

After the taking of testimony in a proceeding, or phase thereof, the presiding officer will afford each participant the opportunity:

(a) To submit written initial briefs in accordance with Rule 706 (briefs before initial decisions), except that the presiding officer may provide an opportunity for oral argument in lieu of, or in addition to, initial briefs; and

(b) To submit written reply briefs in accordance with Rule 706 (briefs before initial decision), except that the presiding officer (1) may provide an opportunity for oral reply argument in lieu of, or in addition to, reply briefs, and (2) may for good cause deny this opportunity for reply or limit the issues which may be addressed in such replies.

§ 385.705 Additional powers of presiding officer with respect to briefs. (Rule 705.)

(a) *Limitations on briefs.* The presiding officer may limit the length of any brief to be filed under Rule 706 (briefs before initial decisions) with due regard to the nature of the proceeding.

(b) *Additional briefs and other filings.* If appropriate, the presiding officer may permit or require briefs or other filings in addition to those provided for in Rule 706 (briefs before initial decision).

§ 385.706 Initial and reply briefs before initial decision. (Rule 706.)

(a) *When filed.* If initial or reply brief are to be filed, the presiding officer will

fix the time for filing and service of such briefs giving due regard to the nature of the proceeding, the extent of the record, and the number and complexity of the issues. Unless specifically ordered otherwise, the time so fixed will be the same for all initial briefs and the same for all reply briefs.

(b) *Contents.* (1) Initial briefs filed with the presiding officer must include:

(i) A concise statement of the case;

(ii) Proposed findings and conclusions, unless waived by the presiding officer;

(iii) Arguments in support of the participant's position, and

(iv) Any other matter required by the presiding officer.

(2) Reply briefs filed with the presiding officer must be limited to responding to arguments and issues raised in the initial briefs, and the presiding officer may impose other limits on the reply brief.

(c) *Form.* (1) Exhibits admitted in evidence or marked for identification in the record must not be reproduced in the brief, but may be shown, within reasonable limits, in an appendix to the brief. Analyses of such exhibits may be included in the brief where pertinent.

(2) A brief of more than 20 pages must contain, in the front, a table of contents and points made, with page references, and a list of citations, alphabetically arranged, with page references.

(d) *Record.* Initial and reply briefs accompany the record and will be available to the Commission and the presiding officer for consideration in deciding the case.

§ 385.707 Oral argument before initial decision. (Rule 707.)

(a) *Procedure.* If oral argument is to be held, the presiding officer will designate the order of the argument, set a time limit on each argument, and make any other procedural rulings.

(b) *Scope.* (1) If oral argument is to be held without an initial brief, then each participant has the opportunity to present orally the information required or permitted to be included in initial briefs pursuant to Rule 708(b) (contents of initial briefs).

(2) If oral argument is to be held in addition to an initial or reply brief, such oral argument may be limited to issues considered by the presiding officer to be appropriate issues for oral argument.

(c) Oral argument will be transcribed and included in the record and must be available to the Commission and the presiding officer in deciding the case.

§ 385.708 Initial decisions by presiding officer. (Rule 708.)

(a) *Applicability.* This section applies to any proceeding in which a presiding officer, other than the Commission, presided over the reception of the evidence.

(b) *General rule.* (1) Unless othewise ordered by the commission or unless paragraph (b)(2) applies, the presiding officer will prepare a written initial decision.

(2) Where time and circumstances so require, the presiding officer may issue an order stating that an oral initial decision will be issued. The oral decision is considered served upon all participants when it is issued orally. Promptly thereafter the presiding officer will prepare the oral initial decision contained in the transcript in the format of a written initial decision.

(3) An initial decision prepared under paragraph (b)(1) or (b)(2) of this section, will be certified by the presiding officer, together with a copy of the record in the proceeding, if any.

(4) After certification of a written initial decision under paragraph (b)(3) of this section, the presiding officer, after notification and having received no objections from the participants, may make technical corrections to the initial decision within 35 days of its certification.

(c) *Initial decision prepared and certified by presiding officer.* (1) The presiding officer who has presided over the reception of evidence must prepare and certify the initial decision, if any, unless such officer becomes unavailable or unless the Commission otherwise provides in accordance with 5 U.S.C. 557(b).

(2) If the presiding officer becomes unavailable, the Chief Administrative Law Judge may issue an order designating another qualified presiding officer to prepare and certify the initial decision.

(d) *Finality of initial decision.* For purposes of rehearing as provided in Rule 713 (requests for rehearing), the initial decision will become a final Commission decision 10 days after exceptions are due under Rule 711 (exceptions after initial decision) unless (1) exceptions are timely filed under Rule 711 (exceptions after initial decision), or (2) the Commission issues an order staying the effectiveness of the decision pending review under Rule 712 (relating to Commission review where no exceptions are filed).

§ 385.709 Other types of decisions. (Rule 709.)

In lieu of an initial decision under Rule 708 (initial decisions), the Commission may order any type of decision as provided by 5 U.S.C. 557(b), or waiver of the initial decision as provided by Rule 710 (waiver of initial decision).

§ 385.710 Waiver of the initial decision. (Rule 710.)

(a) *General rule.* A participant may file a motion asking the Commission to issue a final decision without any initial decision. If all other participants join in the motion, it is granted unless the Commission denies the motion within 10 days after the date of filing or in the case of an oral motion under paragraph (c)(2) of this section within 10 days after the motion is transmitted to the Commission.

(b) *Content.* The motion filed with the Commission must specify:

(1) Whether all participants concur in the request to waive the initial decision;

(2) The reasons that waiver of the initial decision is in the interest of parties and the public interest;

(3) Whether any participant desires an opportunity for filing briefs;

(4) Whether any participant desires an opportunity for oral argument before the presiding officer, the Commission, or an individual Commissioner; and

(5) Whether any participant waives any other procedural right.

(c) *How and when made.* (1) A written motion under this section may be filed at any time before the matter is set for hearing, during the hearing, but no later than 5 days after the close of the hearing conducted under Subpart E.

(2) An oral motion under this section may be made during a hearing session, in which case the presiding officer will transmit the relevant portions of the transcript of the hearing in which the motion was made to the Commission.

§ 385.711 Exceptions and briefs on exceptions after initial decision. (Rule 711.)

(a) *Exceptions.* (1) Within 30 days after service of an initial decision, a participant may file with the Commission exceptions to the initial decision in a brief on exceptions. A brief opposing exceptions may be filed in response to a brief on exceptions within 20 days after the latest date for filing a brief on exceptions. A participant may, within the time set for filing briefs opposing exceptions, file a brief on exceptions solely for the purpose of incorporating by reference one or more numbered exceptions contained in another participant's brief. A brief filed under the preceding sentence need not comply with the requirements set forth in paragraph (b) of this section.

(2) A brief on exceptions or a brief opposing exceptions must not exceed 50 pages in length, unless the Chief Administrative Law Judge, upon motion, changes the page limitation.

(3) The Secretary may extend, on motion or upon direction of the Commission, the time limits for such briefs. No further briefs are permitted unless specifically ordered by the Commission.

(b) *Nature of briefs on exceptions and of briefs opposing exceptions.* (1) A brief on exceptions and a brief opposing exceptions must include:

(i) If the brief exceeds 10 pages in length, a separate summary of the brief no more than five pages in length; and

(ii) A presentation of the participant's position and arguments in support thereof, including references to the pages of the record or exhibits where evidence appears in support of such position and arguments.

(2) A brief on exceptions must include, in addition to matters required by paragraph (b)(1) in this section:

(i) A short statement of the case;

(ii) A list of numbered exceptions, including a specification of each error of fact or law asserted; and

(iii) A concise discussion of the policy considerations that may warrant full Commission review and opinion.

(3) A brief opposing exceptions must include, in addition to matters required by paragraph (b)(1) of this section:

(i) A list of exceptions opposed, by number; and

(ii) A rebuttal of policy considerations claimed to warrant Commission review.

(c) *Oral argument.* (1) A participant filing a brief on exceptions or brief opposing exceptions may request, by written motion, oral argument before the Commission or an individual Commissioner.

(2) The motion must be filed within the time limit for filing briefs opposing exceptions.

(3) No replies to such a motion will be entertained.

(4) The motion may be granted at the discretion of the Commission. If oral argument is granted, it will be limited, unless otherwise specified, to matters properly raised by the briefs.

(d) *Failure to take exceptions results in waiver*—(1) *Complete waiver.* Failure to file a brief on exceptions within the time permitted under this section constitutes a waiver of all objections to the initial decision.

(2) *Partial waiver.* Failure to object to any part of an initial decision in a brief on exceptions constitutes a waiver of objections to that part of the initial decision.

(3) *Effect of waiver.* Unless otherwise ordered by the Commission upon a showing of good cause, a participant who has waived objections under paragraphs (d)(1) or (d)(2) of this section to all or part of the initial decision may not thereafter raise his objections to the initial decision before the Commission in oral argument or on rehearing.

§ 385.712 Commission review of initial decision in the absence of exceptions. (Rule 712.)

(a) *General rule.* If no briefs on exceptions to an initial decision are filed within the time established by rule or order under Rule 711 (briefs on exceptions), the Commission may, within 10 days after the expiration of such time, issue an order staying the effectiveness of such decision pending its review.

(b) *Briefs and argument.* When it reviews a decision under this section, the Commission may require the participants to file briefs or present oral arguments on any issue.

(c) *Effects of review.* After Completing review under this section, the Commission will issue a decision which is final for purposes of Rule 713 (requests for rehearing).

§ 385.713 Request for rehearing. (Rule 713.)

(a) *Applicability.* This section applies to any Commission final decision or other final order with respect to rehearing provided for by statute, rule, or order.

(b) *Time for filing.* A request for rehearing may be filed by any party within 30 days after issuance of any final decision or other final order in a proceeding.

(c) *Final decisions.* In the case of a proceeding set for hearing under Subpart E:

(1) For the purposes of paragraph (a) of this section, a final decision includes a Commission decision:

(i) On exceptions taken by participants to an initial decision;

(ii) When the Commission has presided at the reception of the evidence;

(iii) When the initial decision procedure has been waived by consent of the participants in accordance with Rule 710 (waiver of initial decision);

(iv) On review of an initial decision in the absence of exceptions in accordance with Rule 712 (Commission review in absence of exceptions); and

(v) Any other action designated as final decision by the Commission for purposes of rehearing.

(2) For the purposes of paragraph (a) of this section, an initial decision under Rule 708 (initial decisions) to which no exceptions were filed and no review was initiated under Rule 712 (Commission review in absence of exceptions) becomes final at the expiration of the time period for Commission review under Rule 712 of this part (Commission review in absence of exceptions).

(d) *Content of request.* A request for rehearing must state concisely the alleged error in the Commission's decision or order. The request must conform to the requirements applicable to pleadings contained in Rule 203(a) (content of pleadings). If rehearing is sought by reason of matters that were not available for consideration by the Commission at the time of its decision, the matters relied upon by the party requesting rehearing must be set forth in the request.

(e) *Answers.* The Commission will not permit answers to requests for rehearing. The Commission may afford the parties an opportunity to file briefs or present oral argument on some or all issues presented by a request for rehearing.

(f) *Request is not stay.* The filing of a request for rehearing does not operate as a stay of the Commission's decision or order unless specifically ordered by the Commission.

(g) *Commission action on rehearing.* Unless the Commission acts upon a request for rehearing within 30 days after it is filed, it is denied.

§385.714 Certified questions. (Rule 714.)

(a) *General rule.* During the course of a proceeding, the presiding officer may certify, and, at the direction of the Commission, will certify to the Commission for its consideration and disposition any question which is germane to the proceeding, including questions of law, policy, or procedure.

(b) *Notice.* The presiding officer will notify the participants of the certification of any question to the Commission and of the date of such certification. Such notification may be made orally during the hearing session or by order.

(c) *Presiding officer's memorandum; views of the participants.* To the extent practicable, the presiding officer should solicit the oral or written views of the participants regarding a question certified under this section. The presiding officer shall prepare a memorandum which sets forth the relevant issues, discusses the views of participants which have been submitted, and recommends a disposition of such issues. Any written views submitted by the participants and the memorandum of the presiding officer shall be appended to the question certified under this section.

(d) *Return of certified question to presiding officer.* If the Commission does not act on a certified question within 30 days after receipt of a certification under paragraph (a) of this section, the question is deemed returned to the presiding officer for decision in accordance with the other provisions of this subpart.

(e) *Certification not suspension.* Unless otherwise directed by the Commission or the presiding officer, certification under this section does not suspend the proceeding.

§385.715 Interlocutory appeals to the Commission from rulings of presiding officers. (Rule 715.)

(a) *General rule.* No appeal to the Commission may be taken from a ruling of a presiding officer during the course of a proceeding, unless the presiding officer under paragraph (b) of this section or the motions Commissioner under paragraph (c) of this section

determines that such ruling should be reviewed by the Commission.

(b) *Motion to the presiding officer to permit appeal.* (1) Any participant in a proceeding may, during the course of the proceeding, move that the presiding officer permit appeal to the Commission from any ruling made by the presiding officer in the proceeding. The motion will state why prompt Commission review is necessary under the standards of paragraph (b)(2) of this section.

(2) Upon receipt of a motion under paragraph (b)(1) of this section, the presiding officer will determine with or without consideration of any answer to such motion, whether to permit appeal of the motion to the Commission. The presiding officer shall permit the appeal only if he finds that extraordinary circumstance exists, such that prompt Commission review of the contested ruling is necessary to prevent detriment to the public interest or irreparable harm to a person.

(3) The presiding officer will issue an order, orally or in writing, containing the determination made under paragraph (b)(2) of this section, including the date of the action permitting an appeal to the Commission.

(4) When an appeal is permitted, the presiding officer will transmit to the Commission:

(i) A memorandum which sets forth the relevant issues and an explanation of the rulings on such issues; and

(ii) The participant's motion under paragraph (b)(1) of this section and any answer permitted thereto, except that this requirement may be waived at the discretion of the presiding officer.

(5) If the presiding officer fails to issue an order under paragraph (b)(2) of this section within 15 days after the motion is filed under paragraph (b)(1) of this section, the motion is denied.

(c) *Appeal of a presiding officer's denial of motion to permit appeal.* (1) If a motion to permit appeal is denied by the presiding officer, the participant who made the motion may appeal the denial to the motions Commissioner in accordance with this paragraph.

(2) A participant must submit an appeal under paragraph (c)(1) of this section within 7 days after the motion under paragraph (b) of this section is denied or deemed denied. The appeal must state why prompt Commission review is necessary under the standards set forth in paragraph (c)(5) of this section.

(3) A copy of the written order denying the motion or, if the denial was issued orally, the relevant portions of the transcript will be filed with the appeal.

(4) The motions Commissioner may order the presiding officer or any participant in the proceeding to provide additional information.

(5) The motions Commissioner will permit the appeal to the Commission only if he determined that extraordinary circumstances exist such that prompt Commission review of the contested ruling is necessary to prevent detriment to the public interest or to prevent irreparable harm to a person. Unless such a determination is made within 7 days after the filing the appeal, or such longer period as the motions Commissioner may provide to receive and consider information under paragraph (c)(4) of this section, the appeal to the Commission will not be permitted. If such appeal is not permitted, the contested ruling of the presiding officer will be reviewed only in accordance with the other provisions of this subpart.

(6) If a motions Commissioner permits an appeal to the Commission, the Secretary will issue an order containing that decision.

(d) *Commission action.* Unless the Commission acts upon an appeal permitted by a presiding officer under paragraph (b) of this section, or by the motions Commissioner under paragraph (c) of this section, within 15 days after the date of such permission, the ruling of the presiding officer will only be considered in accordance with the other provisions of this subpart.

(e) *Appeal not to suspend proceeding.* A decision by a presiding officer to permit appeal under paragraph (b) of this section or by the motions Commissioner to permit an appeal under paragraph (c) of this section will not suspend the proceeding unless otherwise ordered by the presiding officer of the motions Commissioner.

§ 385.716 Reopening. (Rule 716.)

(a) *General rule.* To the extent permitted by law, the evidentiary record in a proceeding may be reopened for good cause for the purpose of taking additional evidence.

(b) *By motion.* Any participant may file a motion to reopen the record which must set forth clearly the facts sought to be proven and the reasons claimed to constitute grounds requiring reopening. A participant who does not file an answer to such motion will be deemed to have waived any objection to the motion if such objection has not been raised by any other participant.

(c) *By action of the presiding officer or the Commission.* The record in a proceeding may be reopened by (1) the presiding officer at any time before the initial decision is served, or (2) the Commission any time thereafter, if the presiding officer or the Commission, as appropriate, has reason to believe that conditions of fact or of law have so changed as to require, or that the public interest requires, the reopening of the record in such proceeding.

Subpart H—Shortened Procedures

§ 385.801 Waiver of hearing. (Rule 801.)

In any proceeding in which the Commission is authorized to act after opportunity for hearing, if the parties waive hearing, such opportunity will be deemed to have been afforded by service or publication in the **Federal Register** of notice of the application or other initial pleading, request, or other filing, such notice fixing a reasonable period of time within which any person desiring to be heard may file a protest or petition. Upon the expiration of such period of time, in the absence of a request for hearing, the Commission may forthwith dispose of the matter upon the basis of the pleadings and other submittals and the studies and recommendations of the staff. A party not requesting oral hearing in its pleadings will be deemed to have waived a hearing for the purpose of such disposition, but will not be bound by such a waiver for the purposes of any request for rehearing with respect to an order so entered.

§ 385.802 Noncontested proceedings. (Rule 802.)

(a) *Where hearing waived.* In any proceeding in which the Commission is authorized to act after opportunity for hearing, if the parties waive hearing, such opportunity shall be deemed to have been afforded by service or publication in the **Federal Register** of notice of the application or other initial pleading, request, or other filing, such notice fixing a reasonable period of time within which any person desiring to be heard may file a protest or petition. Upon the expiration of such period of time, in the absence of a request for hearing, the Commission may forthwith dispose of the matter upon the basis of the pleadings and other submittals and the studies and recommendations of the staff. A party not requesting oral hearing in its pleadings shall be deemed to have waived a hearing for the purpose of such disposition, but shall not be bound by such waiver for the purposes of any application for rehearing with respect to an order so entered.

(b) *Noncontested proceedings.* In any proceeding required by statute to be set for hearing, the Commission, when it appears to be in the public interest and to be in the interest of the parties to grant the relief or authority requested in the initial pleading, and to omit the intermediate decision procedure, may, after a hearing during which no opposition or contest develops, forthwith dispose of the proceedings upon consideration of the pleadings and other evidence filed and incorporated in the record: *Provided,* (1) The applicant or other initial pleader requests that the

intermediate decision procedure be omitted and waives oral hearing and opportunity for filing exceptions to the decision of the Commission; and (2) no issue of substance is raised by any request to be heard, protest or petition filed subsequent to publication in the **Federal Register** of the notice of the filing of an initial pleading and notice or order fixing of hearing, which notice or order will state that the Commission considers the proceeding a proper one for disposition under the provisions of this subpart. Requests for the procedure provided by this subpart may be contained in the initial pleading or subsequent request in writing to the Commission. The decision of the Commission in such proceeding after noncontested hearing, will be final, subject to reconsideration by the Commission upon request for rehearing as provided by statute.

Subpart I—Commission Review of Remedial Orders

§ 385.901 Scope. (Rule 901.)

(a) *Proceedings to which applicable.* The provisions of this subpart apply to proceedings of the Commission held in accordance with section 503(c) of the Department of Energy Organization Act (42 U.S.C. 7193(c)) to review orders issued by the Secretary of Energy pursuant to section 503(a) of the Department of Energy Organization Act (42 U.S.C. 7193(c)), and initiated by notices of probable violation, proposed remedial orders, or other formal administrative initiating documents issued on or after October 1, 1977, which are contested by the recipient.

(b) *Relationship to other rules.* (1) Where provision of this subpart is inconsistent with provision in any other subpart of this part, the former provision controls.

(2) Subpart F of this part, except Rule 601, does not apply to proceedings under this subpart.

§ 385.902 Definitions. (Rule 902.)

For purposes of this subpart:

(a) "Contested order" means the remedial order, interim remedial order for immediate compliance or order of disallowance being contested in proceeding pursuant to this subpart;

(b) "Interim remedial order for immediate compliance" means an interim remedial order for immediate compliance issued pursuant to 10 CFR 205.199D (interim remedial order of immediate compliance);

(c) "Order of disallowance" means an order of disallowance issued pursuant to 10 CFR § 205.199E (disallowance);

(d) "Participant" means, as appropriate, the Secretary, the petitioner, and intervenors;

(e) "Petitioner" means a person who has received a remedial order, interim remedial order for immediate compliance, or order of disallowance who notifies the Secretary that he intends to contest the order;

(f) "Remedial order" means a remedial order issued pursuant to 10 CFR § 205.199B (remedial orders);

(g) "Secretary" means the Secretary of Energy or his delegate.

§ 385.903 Request for nondisclosure of information. (Rule 903.)

(a) For purposes of this section, nondisclosure means nondisclosure except as to the participants in the proceeding under conditions provided in paragraphs (d) and (e) of this section.

(b) If any person filing under this subpart claims that some or all of the information contained in a document is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in Section 1905 of title 18 of the *United States Code* (18 U.S.C. 1905) (disclosure of confidential information), or is otherwise exempt by law from public disclosure, the person:

(1) Must request the presiding officer not to disclose such information, except to the participants in the proceeding under the conditions provided in paragraphs (d) and (e) of this section; which request the person must serve upon the participants in the proceeding;

(2) Must file, together with the document, a second copy of the document from which has been deleted

the information for which the person requests nondisclosure and must indicate in the original document that the original document is exempt, or contains information which is exempt, from disclosure;

(3) Must include a statement specifying why the information is privileged or confidential, if the information for which nondisclosure is requested is claimed to come within the exception in 5 U.S.C. 552(b)(4) for trade secrets and commercial or financial information;

(4) Must include a statement specifying the justification for nondisclosure, if the information for which nondisclosure is requested is not within the exception in 5 U.S.C. 552(b)(4).

(c) If the person filing a document does not submit a second copy of the document from which the appropriate information has been deleted, the presiding officer may assume that there is no objection to public disclosure of the document in its entirety.

(d) If information is submitted in accordance with paragraph (b) of this section, the information will not be disclosed except as provided in the Freedom of Information Act, in accordance with Part 388 of this subchapter and upon request in accordance with paragraph (e) of this section, to participants in the proceeding under the restrictions that the participants may not use or disclose the information except in the context of the proceeding conducted pursuant to this subpart and that the participants must return all copies of the information at the conclusion of the proceeding to the person who submitted the information under paragraph (b) to this section.

(e) At any time, a participant may request the presiding officer to direct a person submitting information under paragraph (b) to this section to provide that information under paragraph (b) to this section to provide that information to the participant requesting the information under this paragraph. The presiding office will so direct if the participant requesting the information agrees:

(1) Not to use or disclose the information except in the context of the proceeding conducted pursuant to this subpart; and

(2) To return all copies of the information, at the conclusion of the proceeding, to the person submitting the information under paragraph (b) of this section.

(f) If the information contained in the record of prior proceedings submitted by the Secretary under Rule 906(a)(1), is determined by the Secretary to be exempt from disclosure, the information shall not be disclosed except:

(1) As provided in the Freedom of Information Act, in accordance with Part 388 of this subchapter, and

(2) Upon request in accordance with paragraph (g) of this section, to participants in the proceeding under the restrictions that the participants may not use or disclose the information except in the context of the proceeding conducted pursuant to this section and that the participants must return all copies of the information at the conclusion of the proceeding to the presiding officer.

(g) At any time, a participant may request the presiding officer to direct that the complete record of prior proceedings, including information determined by the Secretary to be exempt from disclosure, be made available to that participant. The presiding officer will so direct if the participant requesting the complete record agrees:

(1) Not to use or disclose the information determined to be exempt except in the context of the proceeding conducted pursuant to this subpart, and

(2) To return all copies of the information determined to be exempt to the presiding officer at the conclusion of the proceeding.

§ 385.904 Commencement of proceeding. (Rule 904.)

(a) Except as provided in paragraph (b) of this section, the proceeding pursuant to this subpart will be

commenced by filing with the Secretary of the Commission, for the Commission, of a written notice by the Secretary that the Secretary has been notified by a petitioner that the petitioner has filed a notice of intent to contest an order reviewable under this subpart. At the same time, the Secretary will serve a copy of the contested order upon other participants in the prior proceedings and upon persons denied intervention in the prior proceedings, and will certify to the Commission that such service has been made, stating the names and addresses of persons served.

(b) The proceeding pursuant to this subpart with respect to an interim remedial order for immediate compliance will be commenced by a petitioner's filing with the Secretary of the Commission, for the Commission, and serving on other participants in the prior proceedings, if any, a notice of petition for review of an interim remedial order for immediate compliance pursuant to 10 CFR 205.199D(i)(1) (interim remedial order of immediate compliance). The Commission will defer consideration of the merits of the order until a final remedial order is issued by the Secretary.

(c) Upon receipt of notice from the Secretary under paragraph (a) of this section, or upon receipt of a notice of a petition for review by the petitioner under paragraph (b) of this section, the Commission or its designee will designate a presiding officer for the proceeding, and the Commission or its designee will notify participants in the prior proceedings and persons denied intervention in the prior proceedings of such designation.

§ 385.905 Stay of contested order. (Rule 905.)

(a) Upon the filing of the notice with the Commission by the Secretary under paragraph (a) of Rule 904 (Commencement of proceedings), or by the petitioner under paragraph (b) of such rule, the contested order will be automatically stayed pending review pursuant to this subpart unless and until, upon request of the Secretary or other participant, the presiding officer finds that the public interest requires immediate compliance with the contested order.

(b) The Secretary or other participants may at any time, prior to the hearing under Rule 909 (hearing), or if there is no hearing, prior to the issuance of a proposed order under Rule 913 (proposed order), file a petition requesting that the contested order not be stayed, or that the stay be lifted, and setting forth the legal and factual basis for the request.

(c) The presiding officer may request a written statement of the views of participants regarding whether the contested order should be stayed or continue to be stayed and may convene an expedited hearing or conference on a petition under paragraph (b) of this section.

(d) The presiding officer may grant the petition requesting immediate compliance where he finds that the public interest so requires and will notify the participants of the determination.

(e) If the presiding officer does not grant the petition under paragraph (b) of this section within 10 days after it is filed, the petition is denied. Prior to the expiration of the 10-day period the presiding officer may extend the period for decision for up to 7 days. At the end of the extension, the petition, if not granted, is denied.

(f) If the petition under paragraph (b) of this section is denied, the presiding officer will notify the participants of such denial.

(g) A grant or denial of petition under paragraphs (b) or (c) of this section may be appealed, within 10 days after the grant or denial, to the Commission in accordance with Rule 715 (relating to interlocutory appeals). The contested order will remain stayed pending the Commission's disposition of the appeal.

§ 385.906 Pleadings. (Rule 906.)

(a) *By the Secretary.* (1) Within 20 days after the filing of notice by the

Secretary under rule 904(a) (commencement of proceedings), the Secretary:

(i) Will file with the Secretary of the Commission for the presiding officer two certified copies of the entire record developed in prior proceedings on the contested order. One copy will be complete and will be a part of the record upon which the order of the Commission is based, and will be available to the participants subject to the conditions set forth in Rule 903 (f) and (g) (nondisclosure of information); the second copy will have had deletions made of information which the Secretary has determined to be confidential or not subject to disclosure;

(ii) Will file with the Secretary for the presiding officer a copy of the contested order; and

(iii) May, in addition, elect to file a statement setting forth the factual elements of the alleged violation, which statement the Secretary will serve on all participants in the proceeding.

(2) If the petitioner requests permission to raise new facts or issues pursuant to Rule 907(a) (new facts and issues), the Secretary may file, within 10 days after the filing of the petitioner's answer, a reply responding to the petitioner's request to raise new facts or issues. In the reply, the Secretary may also request the permission of the presiding officer to raise new facts or issues under the criteria set forth in Rule 907(b) (new facts and issues) and to conduct discovery relating to the new facts or issues he may raise pursuant to Rule 907(b) (new facts and issues). Failure by the Secretary to request permission to raise new facts or issues or to conduct discovery in this reply constitutes a waiver of the opportunity to do so at a later time in the proceeding.

(3) The Secretary will file with the Secretary of the Commission, for the presiding officer, and serve upon other participants in the proceedings, a brief in support of the affirmative case, which will set forth:

(i) The elements of the alleged violation, including references to the authorities upon which the Secretary relies, including but not limited to regulations, rulings, interpretations and decisions on appeals and exceptions issued by the Department or its predecessor agencies and precedents established by the Commission; and

(ii) A complete statement of the factual and legal basis of the contested order.

(4) The Secretary's brief will be filed according to the following time period appropriate to the particular proceeding:

(i) If no participant (including persons requesting intervention) has requested permission to raise new facts or issues or to conduct discovery pursuant to paragraphs (a)(2), (b)(2), (c)(7), and (c)(8) of this section, within 20 days after the filing of the petitioner's answer under paragraph (b)(1) of this section;

(ii) If the presiding officer has determined, under Rule 908(d) (discovery) that no discovery shall be permitted, within 20 days after the presiding officer's determination under such rule;

(iii) If discovery is permitted under Rule 908(d) (discovery) within 20 days after the conclusion of the time period set for discovery under such rule;

(b) *By the petitioner.* (1) Within 15 days after the filing by the Secretary under paragraph (a)(1) of this section, the petitioner must file with the Secretary of the Commission, for the presiding officer, and serve upon the Secretary and other participants in the proceedings, an answer to the contested order admitting or denying each of the Secretary's findings in the contested order and setting forth affirmative defenses, if any.

(2) In the answer, the petitioner may:

(i) Contest any part of the record which the Secretary certified to the presiding officer under paragraph (a)(1)(i) of this section;

(ii) Request permission to raise new facts or issues not raised in the prior proceedings if the new facts or issues meet the criteria set forth in Rule 907(a) (new facts and issues); and

(iii) Request permission to conduct discovery, subject to criteria provided in Rule 908(a) (discovery). Failure by the petitioner to contest the record or to request permission to raise new facts or issues or to conduct discovery in this answer constitutes a waiver of the opportunity to do so at a later time in the proceeding.

(3) Within 15 days after filing of the Secretary's brief under paragraph (a)(3) of this section, the petitioner shall file with the Secretary of the Commission, for the presiding officer, and serve upon other participants in the proceeding, a brief stating fully the objections to the contested order, including references to the authorities upon which the petitioner relies, including but not limited to regulations, rulings, interpretations, and decisions on appeals and exceptions issued by the Department or its predecessor agencies and precedents established by the Commission.

(c) *By interveners.* (1) A person qualifying under paragraph (c)(2) of this section, may request the presiding officer to permit intervention in the proceeding under this subpart in accordance with the procedures described in this paragraph.

(2) A motion to intervene may be filed by any person claiming:

(i) An interest which may be directly affected and which is not adequately protected by existing parties and as to which the persons requesting intervention may be bound by the Commissions action in the proceeding; or

(ii) Any other interest of such nature that participation by the person requesting intervention may be in the public interest.

(3) A motion to intervene must set forth clearly and concisely the facts from which the nature of the requester's alleged right or interest can be determined, the grounds of the proposed intervention, and the position of the intervener in the proceeding, so as fully and completely to advise the participants and the presiding officer as to the specific issues of fact or law to be raised or controverted, by admitting, denying, or otherwise answering, specifically and in detail, each material allegation of fact or law raised or controverted, including references to the authorities upon which the requester relies, including, but not limited to, regulations, rulings, interpretations, and decisions on appeals and exceptions issued by the Department or its predecessor agencies and precedents established by the Commission.

(4) Motions to intervene may be filed with the Secretary of the Commission, for the presiding officer, within 20 days after the Secretary's commencement of the proceeding under Rule 904 (commencement of proceedings) unless, in extraordinary circumstances and for good cause shown, the presiding officer authorizes a late filing. A person requesting intervention must serve the motion to intervene on the participants in the proceeding at the same time the request is filed with the Secretary of the Commission.

(5) A participant in the proceedings may file an answer to a motion to intervene. Failure to object constitutes a waiver of any objection to the granting of such request. If made, answers must be filed within 15 days after the filing of the request to intervene.

(6) After expiration of the time for filing answers to requests to intervene or default thereof, as provided in paragraph (c)(5) of this section, the presiding officer will grant or deny such request, in whole or in part, or may, if found to be appropriate, authorize limited participation. The presiding officer will serve the determination on a motion to intervene upon the participants in the proceeding and upon the person requesting intervention. If the presiding officer denies a motion for intervention, the person requesting intervention may submit comments to the Commission under Rule 913(c) (proposed order) requesting the Commission to permit the intervention under the standards set forth in paragraph (c)(2) of this section.

(7) A person filing a motion to intervene, may request therein the permission of the presiding officer to

raise new facts or issues not raised in the prior proceedings on the contested order, if the new facts or issues meet the criteria set forth in Rule 903(c) (request for nondisclosure of information). Failure by the person requesting permission to intervene to request permission to raise new facts or issues in the motion to intervene constitutes a waiver of the opportunity to do so at a later time in the proceeding.

(8) A person filing a motion to intervene may request the permission of the presiding officer to conduct discovery, subject to the conditions set forth in Rule 908(c) (discovery). Failure by the person requesting permission to intervene to request permission to conduct discovery in the motion to intervene constitutes a waiver of the opportunity to do so at a later time in the proceeding.

§ 385.907 New facts and issues. (Rule 907.)

(a) *Raised by the petitioner.* In the answer, as provided in Rule 906(b)(2)(ii) (new facts and issues) the petitioner may request permission of the presiding officer to raise new facts or issues not raised in prior proceedings on the contested order that:

(1)(i) Are facts or issues that were not known and could not, with the exercise of due care, have been known to the petitioner at the time they would otherwise have been raised during the prior proceedings;

(ii) Are facts or issues that the petitioner was unable to raise at the time they could have been raised during the prior proceedings because of unduly restrictive time limits imposed by the Secretary; or

(iii) Are facts or issues that the petitioner was not permitted to raise in the prior proceedings due to erroneous adverse procedural rulings; and

(2) Are necessary for a full and true disclosure of the facts.

(b) *Raised by the Secretary.* In the reply under Rule 906(a)(2) (pleadings), the Secretary may request permission of the presiding officer to raise new facts or issues not raised in prior proceedings on the contested order that:

(1) Are necessary to support the Secretary's case as a result of new facts or issues raised by the petitioner under Rule 906(b)(2)(ii) (pleadings) and this section; and

(2) Are necesary for a full and true disclosure of the facts.

(c) *Raised by interveners.* In the motion to intervene under Rule 906(c)(3) (pleadings) and this section, an intervener may request permission of the presiding officer to raise new facts or issues not raised in prior proceedings on the contested order that:

(1) If the intervener did not participate in the prior proceeding, meet the criteria of paragraphs (a)(1) and (a)(2) of this section; or

(2) If the intervener participated in the prior proceedings, are:

(i)(A) Facts or issues that were not known and could not, with the exercise of due care, have been known to the intervener at the time they would otherwise have been raised during the prior proceedings;

(B) Facts or issues that the intervener was unable to raise at the time they could have been raised during the prior proceedings because of unduly restrictive time limits imposed by the Secretary; or

(C) Facts or issues that the intervener was not permitted to raise in the prior proceedings due to erroneous adverse procedural rulings; and

(ii) Are necessary for a full and true disclosure of the facts.

(d) *Determination by the presiding officer.* The presiding officer will determine whether to grant or deny, in whole or in part, the requests of the participants to raise new facts or issues and will serve those determinations on the participants in the proceeding.

§ 385.908 Discovery. (Rule 908.)

(a) *By petitioner.* In the answer under Rule 906(b)(2) (pleadings), the petitioner may request permission of the presiding officer to conduct discovery, where such discovery:

(1) Relates to new facts or issues raised in accordance with Rule 907(a) (new facts and issues); or

(2)(i) Was not permitted in the prior proceedings on the contested order due to erroneous adverse procedural rulings; and

(ii) Is necessary for a full and true disclosure of the facts.

(b) *By the Secretary.* In the reply under Rule 906(a)(2) (pleadings), the Secretary may request permission of the presiding officer to conduct discovery where such discovery relates to new facts or issues raised in accordance with Rule 907(b) (new facts and issues).

(c) *By interveners.* In a motion to intervene under Rule 906(c)(8) (pleadings) an intervener may request permission of the presiding officer to conduct discovery where such discovery:

(1) Relates to new facts or issues raised in accordance with Rule 907(c) (new facts and issues); or

(2) If the intervener participated in the prior proceedings,

(i) Such discovery was not permitted in prior proceedings on the contested order due to erroneous adverse procedural rulings; and

(ii) Such discovery is necessary for a full and true disclosure of the facts.

(d) *Determinations by the presiding officer.* The presiding officer will determine whether to grant or deny, in whole or in part, the requests of the participants for discovery and will set a time limit within which discovery must be conducted.

(e) *Interrogatories.* In addition to discovery devices applicable to this subpart under other subparts of this part, participants may conduct discovery by means of written interrogatories under conditions determined by the presiding officer.

§ 385.909 Hearing. (Rule 909.)

(a) Participant may file, within 10 days after filing of the petitioner's brief under Rule 906(b)(3) (pleadings), a request for a hearing or a motion for the opportunity for cross-examination including the reasons why cross-examination is necessary for a full and true disclosure of the facts.

(b) If a participant has filed a request for a hearing, the presiding officer will grant the request for a hearing. The hearing will include an opportunity for the submission of oral or documentary evidence and oral arguments.

(c) The presiding officer may at any time, convene a hearing.

(d) As soon as practicable after receiving a request for hearing under paragraph (a) of this section or after determination that a hearing will be held under paragraph (c) of this section, the presiding officer will give notice to the participants of the time and place of the hearing.

(e) The presiding officer will determine the issues to be resolved in the proceeding, may specify the time available for oral argument, and will give notice thereof to the participants. The presiding officer may require additional information from the participants, and may convene a prehearing conference for the purpose of determining the issues or the nature of the proceeding to be held.

(f) If at any time prior to the issuance of a proposed order pursuant to Rule 913 (proposed order), with or without a motion of a participant, the presiding officer determines that it is necessary for a full and true disclosure of the facts, the presiding officer may order that the participants be afforded the opportunity for cross-examination on any facts or issues raised in the proceeding.

§ 385.910 Conduct of the hearing. (Rule 910.)

The presiding officer is responsible for conduct of the hearing, including the order of procedure.

§ 385.911 Burden of proof. (Rule 911.)

(a) The Secretary has the burden of going forward and must sustain the burden of proof with respect to disputed elements of affirmative case of the Secretary.

(b) The proposed order under Rule 913 (proposed order) will be based upon a preponderance of the evidence.

§ 385.912 Proposed findings of fact, conclusions of law, and comments. (Rule 912.)

(a) Within 10 days after the conclusion of the hearing, or, if no hearing is held, within 20 days after the filing of the petitioner's brief under Rule 906(b)(3) (pleadings), a participant may file with the Secretary of the Commission for the presiding officer, and serve upon the other participants proposed findings of fact and conclusions of law, comments, in support thereof and any objections with respect to procedural rulings of the presiding officer.

(b) Within 10 days after the filing of proposed findings of fact and conclusions of law under paragraph (a) of this section, a participant may file, and must serve on other participants, a reply thereto.

§ 385.913 Proposed order. (Rule 913.)

(a) After the conclusion of the hearing and after the filings under Rule 912 (a) and (b), (proposed findings of fact, conclusions of law, and comments) the presiding officer will issue a decision and proposed order based on findings of fact affirming, modifying, or vacating the contested order or directing other appropriate relief. The proposed order will be based on the entire record before the presiding officer, including the record of prior proceedings certified by the Secretary.

(b) The presiding officer will certify and file with the Secretary of the Commission, for the Commission, a copy of the record in the proceedings, including the proposed order.

(c) Participants may file, within 15 days of issuance of the proposed order of the presiding officer, with the Secretary of the Commission, for the Commission, written comments on any rulings of the presiding officer and the decision and proposed order.

§ 385.914 Commission action. (Rule 914.)

The Commission will upon consideration of the entire record and the proposed order, issue a final order affirming, modifying, or vacating the contested order or directing other appropriate relief. The Commission will serve the final order on the participants.

§ 385.915 Ex parte communications. (Rule 915.)

The provisions of Rule 2201 (*ex parte* communications) apply to proceedings pursuant to this section, commencing at the time the Secretary issues a proposed remedial order under 10 CFR 205.192, an interim remedial order for immediate compliance under 10 CFR 205.199D, or a proposed order of disallowance under 10 CFR 205.199E, as if proceedings were contested on-the-record proceedings pending before the Commission.

§ 385.916 Withdrawal of petition for review. (Rule 916.)

(a) At any time, including after a hearing has been held or convened, the petitioner may submit to the presiding officer, and serve on other participants in the proceeding, a withdrawal of the petition for review of the contested order. The presiding officer will thereupon issue, and serve the participants, an order terminating the proceeding conducted pursuant to this subpart, which order will be effective 10 days after issuance.

(b) Termination of the proceeding under paragraph (a) of this section, may be appealed to the Commission, within 10 days after issuance of the termination order, except that if the Commission does not act on an appeal within 30 days, it is deemed denied. The termination order is stayed pending the appeal. If the Commission rescinds the termination order, the proceeding will continue in accordance with this subpart.

§ 385.917 Sanctions. (Rule 917.)

Whenever it appears to the Commission that a person is engaged or about to engage in any act or practice

which constitutes or will constitute a violation of rule, regulation, or order, made or imposed by the Commission or the presiding officer under this subpart, it may bring an action in the proper court of the United States to enjoin that act or practice and to enforce compliance with the order, and upon a proper showing, a permanent or temporary injunction or decree or restraining order will be granted without bond. The Commission may transmit such evidence as may be available concerning that act or practice to the Attorney General, who may institute the necessary criminal proceedings.

Subpart J—Commission Review of Adjustment Request Denials

§ 385.1001 Scope. (Rule 1001.)

(a) *Applicability.* This section applies to proceedings of the Commission held in accordance with section 504(b) of the Department of Energy Organization Act, 42 U.S.C. 719(b), to review orders issued by the Secretary of Energy pursuant to section 504(a) of the Department of Energy Organization Act denying, in whole or in part, requests for adjustments.

(b) *Relationship to other rules.* When a provision of this subpart is inconsistent with a provision of any other subpart of this part, the former provision controls.

§ 385.1002 Definitions. (Rule 1002.)

For purposes of this subpart:

(a) "Commission" includes an officer or employee designated as presiding officer in a proceeding under this subpart.

(b) "Petitioner" means a person who is aggrieved or adversely affected by a contested order, as defined in this section, and who requests a review, pursuant to this subpart, by the Commission of the denial by the Secretary.

(c) "Secretary" means the Secretary of Energy or his delegate.

(d) "Content order" means the decision or order issued by the Secretary denying, in whole or in part, a request for adjustment.

(e) "Participant" means, as appropriate, the petitioner, the Secretary, or an intervener.

§ 385.1003 Request for nondisclosure of information. (Rule 1003.)

(a) For purposes of this section, nondisclosure means nondisclosure except to the participants in the proceedings and under the conditions as provided in paragraph (e) of this section.

(b) If a person filing under this subpart claims that some or all of the information contained in a document is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt by law from public disclosure, the person:

(1) Will request the presiding officer not to disclose such information, except to the participants in the proceedings and under the conditions as provided in paragraph (e) of this section, which request the person must serve upon the participants in the proceedings;

(2) Will file, together with the document, a second copy of the document from which has been deleted the information for which the person requests nondisclosure and must indicate in the original document that the original document is confidential or contains confidential information;

(3) If the information is claimed to come within the exception in 5 U.S.C. 552(b)(4), for trade secrets and commercial or financial information, it must include a statement specifying why the information is privileged or confidential;

(4) If the information for which nondisclosure is requested is not within the exception in 5 U.S.C. 552(b)(4), it must include a statement specifying the justification for nondisclosure.

(c) If the person filing a document does not submit a second copy of the document from which the appropriate information has been deleted, the presiding officer may assume that there

is no objection to public disclosure of the document in its entirety.

(d) A participant in the proceedings who opposes a request for nondisclosure under paragraph (b) of this section must file, within 10 days of the receipt of a copy of the request for non-disclosure, with the presiding officer, and serve on the other participants, a statement specifying the reasons that the material is not exempt from disclosure.

(e) The presiding officer will make an independent determination as to a request filed under this section and will serve that determination upon the participants in the proceedings. If a request for nondisclosure is denied, in whole or in part, the requesting person will be given notice thereof and will be afforded an opportunity to respond, no less than 5 days prior to public disclosure. If the request for nondisclosure is granted, in whole or in part, the presiding officer will issue an order stating that the information will not be disclosed except, upon request, to the participants in the proceedings, that the participants may not use or disclose the information, except in the context of the proceedings conducted pursuant to this subpart, and that upon conclusion of the proceedings, the participant return the information to the presiding officer.

§ 385.1004 Commencement of proceedings. (Rule 1004.)

(a) A petitioner commences proceedings, pursuant to this subpart, by filing with the Commission and serving upon the Secretary and any other participants in prior proceedings on the contested order a petition for review, which must contain:

(1) A copy of the decision or order denying, in whole or in part, request for adjustment (the contested order); and

(2) A complete statement of the petitioner's objections factual or legal to the contested order, including references to all authorities upon which the petitioner relies including but not limited to regulations, rulings, interpretations, and decisions on exceptions and appeals issued by the Department or its predecessor agencies and precedents established by the Commission.

(b) A petition for review must be filed within 30 days of issuance by the Secretary of the order to be contested pursuant to this subpart.

(c) Upon receiving a petition for review, the Commission or its designee will designate a presiding officer for the proceedings.

§ 385.1005 Replies. (Rule 1005.)

(a) *By the Secretary.* Within 15 days of service of the petition for review, the Secretary:

(1) Will file with the Commission a certified copy of the complete record developed in prior proceedings on the contested order, which will be available at the Commission for inspection by the participants; and

(2) Will file with the Commission and serve on the petitioners and the other participants in prior proceedings on the contested order, a reply to the petition for review stating fully his or her position supported by arguments to the petition for review.

(b) *By other participants.* A person who participated in prior proceedings on the contested order may be a participant in the proceedings pursuant to this subpart and may make filings and submittals as determined by the presiding officer.

(c) *By interveners.* A person who was denied the opportunity to participate in prior proceedings on the contested order or who is aggrieved or adversely affected by the contested order may move to intervene in accordance with Rule 214 (intervention). In order that the motion be granted, the movant must show, as appropriate, that denial of participation in prior proceedings was wrongful or why he or she is aggrieved or adversely affected by the contested order. If the presiding officer grants the motion, the person submitting the motion to intervene may make filings and submittals as determined by the presiding officer.

(d) A participant may request interim relief in a proceeding pursuant to this subpart.

(e) The presiding officer may require such other filings by the participants as he or she deems necessary in the conduct of the proceedings.

§ 385.1006 Request for hearing. (Rule 1006.)

A participant may file with the Commission and serve on the other participants a request for hearing, which will be deemed granted.

§ 385.1007 Presiding officer. (Rule 1007.)

(a) The presiding officer will determine the issues to be resolved in the proceeding and will give notice thereof to the participants. The presiding officer may require additional information from the participants and convene a prehearing conference for the purpose of determining the issues to be considered at a hearing, if one is to be held. The presiding officer may also specify the time available for oral argument and determine the nature of the hearing to be held.

(b) The presiding officer may determine, upon request by a participant, whether to permit the participant to raise new facts or issues not raised in prior proceedings on the contested order. Such a request may be granted if the facts or issues are facts or issues that:

(1)(i) Were not known and could not, with the exercise of due care, have been known to the participant at the time they could have been raised in prior proceedings; or

(ii) Are facts or issues that the participant was not permitted to raise in prior proceedings on the contested order due to an adverse procedural ruling alleged to be erroneous; and

(2) Are necessary for a full and true disclosure of the facts.

§ 385.1008 Hearings. (Rule 1008.)

As soon as practicable, after receiving any request for hearing and all the pleadings under Rules 1004 (commencement of proceedings) and 1005 (replies), the presiding officer will give notice to the participants as to the time and place of the hearing.

§ 385.1009 Proof. (Rule 1009.)

(a) A participant seeking relief from the Secretary's denial of a request for adjustment has the burden of demonstrating the participant's entitlement to the relief sought.

(b) Relief will be granted under this subpart if a participant demonstrates, by a preponderance of the evidence, that such relief is warranted.

§ 385.1010 Proposed order. (Rule 1010.)

(a) As soon as practicable, after receipt of all the pleadings or after the hearing, if one is held, the presiding officer will issue, and serve upon the participants in the proceedings, a proposed order based upon findings of fact, affirming, modifying or vacating, the contested order or directing other appropriate relief.

(b) The presiding officer will certify and file with the Office of the Secretary of the Commission, for the Commission, a copy of the record in the proceeding, including the proposed order.

(c) Participants may file, within 15 days of service of the proposed order, with the Secretary of the Commission, for the Commission, written comments on the proposed order.

§ 385.1011 Final order. (Rule 1011.)

The Commission will issue a final order, affirming, modifying or vacating the contested order or directing other appropriate relief.

§ 385.1012 Ex parte communications. (Rule 1012.)

The provisions of Rule 2201 (*ex parte* communications) apply to proceedings pursuant to this subpart, commencing at the time a petitioner files a petition for review under Rule 1004 (commencement of proceedings), as if such proceedings were contested on-the-record proceedings pending before the Commission.

Subpart K—Petitions for Adjustments Under the NGPA

§ 385.1101 Applicability. (Rule 1101.)

(a) *Proceedings to which applicable.* Except as provided in paragraph (b) of this section, this subpart applies to proceedings of the Commission held in accordance with:

(1) Section 502(c) of the NGPA to provide for adjustments of:

(i) Commission rules, and

(ii) Commission orders having the applicability and effect of a rule as defined in section 551(4) of title 5 of the *United States Code* (5 U.S.C. 551(4)) and issued under the NGPA, except orders issued under sections 301, 302, and 303 of the NGPA;

(2) Section 206(d) of the NGPA to provide for exemptions for industrial boiler fuel facilities from incremental pricing provisions of the NGPA under § 282.206 of this chapter.

(b) This subpart does not apply to:

(1) Proceedings wherein the Commission by order grants an adjustment on its own motion or;

(2) Proceedings for which the Commission by order waives the provision of this subpart.

(c) *Relationship to other rules.* (1) Where a provision of this subpart is inconsistent with a provision in another subpart of this part, the former provision controls.

(2) When provisions of other subparts of this part require Commission action, such provisions as applied under this subpart shall be deemed to require staff action. This subpart does not require a hearing to which Subpart E applies.

§ 385.1102 Definitions. (Rule 1102.)

For purposes of this subpart:

(a) "Adjustment" means an order issued by Staff under Rule 1109 (orders):

(1) Granting relief from an order or rule issued by the Commission under the NGPA,

(i) Including exceptions, exemptions, modification, and recissions of rules and orders have the effect of rule as defined in section 551 of title 5 of the *United States Code* (5 U.S.C. 551(4)) and issued under the NGPA; but

(ii) Excluding requests for just and reasonable rates under sections 104, 106, and 109 of the NGPA; and

(2) Granting an exemption, in whole or in part, for incrementally priced industrial boiler fuel facilities from section 201 of the NGPA, under the authority of section 206(d) of the NGPA and § 282.206 (industrial boiler fuel facilities exemption);

(b) "Petitioner" means a person who files a petition for adjustment under paragraph (c) of this section;

(c) "Petition" means a petition for adjustment filed under Rule 1103 (commencement of adjustment proceedings);

(d) "NGPA" means the Natural Gas Policy Act of 1978;

(e) "Party" means, with respect to a particular petition for adjustment, the person making the petition, an intervener, or a person who has moved to intervene but whose motion has not been granted or denied under Rule 1105(b) (intervention in adjustment proceedings).

(f) "Staff" means the Director of the Office of Producer and Pipeline Regulation, or a person who is designated by the Director and who is an employee of the Commission.

§ 385.1103 Commencement of proceeding. (Rule 1103.)

A person commences a proceeding for an adjustment by filing a petition for adjustment with the Commission.

§ 385.1104 Initial petition. (Rule 1104.)

(a) *Content.* (1) *The petition must contain:*

(i) A full and complete statement of the relevant facts, including the documentary support pertaining to the circumstances, act or transaction that is the subject of the application;

(ii) A complete statement of the business reasons why the relief should be granted and the business consequences that will result if the relief is denied; and

(iii) A statement specifying how the denial or relief will cause the applicant to suffer special hardship, inequity, or unfair distribution of burdens.

(2) The petition must contain a complete statement of the legal basis of the relief requested including citations to authorities relied upon to support the petition.

(3) The petition must specify the exact nature of the relief sought.

(4) The certificate of service required under Rule 2010(h) (certificate of service) must indicate the names and addresses of all persons served.

(5) The petition must include a proposed notice of the adjustment proceeding which must state the petitioner's name, the rule or order under the NGPA of which an adjustment is sought, the date of the petition, and a brief summary of the relief requested. The proposed notice must be in the following form:

United States of America, Federal Energy Regulatory Commission

(Name of Petitioner) _____

Docket No. _____ _____

Notice of Petition for Adjustment

On (date petition was filed), (name of petitioner) filed with the Federal Energy Regulatory Commission a petition for an adjustment under (the rule or order under the NGPA of which an adjustment is sought), wherein (name of petitioner) sought (relief requested).

The procedures applicable to the conduct of this adjustment proceeding are found in Subpart K of the Commission's Rules of Practice and Procedure.

Any persons desiring to participate in this adjustment proceeding must file a motion to intervene in accordance with the provisions of such Subpart K. All motions to intervene must be filed within 15 days after publication of this notice in the **Federal Register**.

(b) *Service.* (1) The petitioner must serve a copy of the petition, or a copy from which confidential information has been deleted in accordance with Rule 1112 (requests for confidential treatment) on each person who is reasonably ascertainable by the petitioner as a person who may suffer direct and measurable economic impact if the relief is granted.

(2) Notwithstanding paragraph (b)(1) of this section, if a petitioner determines that compliance with such paragraph of this section would be impracticable, the petitioner must:

(i) Comply with the requirements of such paragraph with regard to those persons whom it is reasonable and practicable to serve; and

(ii) Include with the petition a description of the persons or class or classes of persons to whom notice was not sent.

(3) Staff may require the petitioner to provide alternate or additional service and will cause notice of the application to be published in the **Federal Register**.

§ 385.1105 Intervention. (Rule 1105.)

(a) A motion to intervene in an adjustment proceeding, in conformity with Rule 214 (intervention) must be filed within 15 days after publication in the **Federal Register** of notice of the petition for adjustment.

(b) A motion to intervene is granted unless it is denied by staff within 75 days after the day on which it was filed.

§ 385.1106 Other filings. (Rule 1106.)

(a) *Interveners.* Responses to the petition must be filed at the time the motion to intervene is filed.

(b) *Petitioner.* The petitioner may respond to filings of another party within 15 days after service of such filings. Amended pleadings may be filed under Rule 215 (amendments) if the petitioner discovers facts unavailable at the time the initial petition was filed, or if such pleadings are requested or permitted by Staff under Rule 1107 (evaluations).

§ 385.1107 Evaluations. (Rule 1007.)

(a) Staff will consider the filings made in connection with the petition for adjustment. Staff may also consider information received under paragraph (b) of this section. If Staff obtains information under paragraphs (b)(1) or (b)(3) of this section and relies upon

such information, the petitioner will be advised of such information and will be given 15 days to respond to such information.

(b)(1) Staff may initiate an investigation of any statement in a petition and use in its evaluation of any relevant fact obtained in such an investigation.

(2) Staff may request additional information from the petitioner.

(3) Staff may solicit and accept submissions from interveners or third persons relevant to the petition.

(4) Staff may consider information obtained in informal conferences held under Rule 1111 (adjustment conferences).

§ 385.1108 Criteria. (Rule 1108.)

(a) Staff will grant a petition where there are sufficient facts to make a determination on the merits and where Staff determines that an adjustment is necessary to prevent or alleviate:

(1) Special hardship;

(2) Inequity; or

(3) An unfair distribution of burdens.

(b) When there are not sufficient facts to make a determination on the merits, the Staff may dismiss the petition without prejudice; except, that when Staff has requested additional material information under Rule 1107 (adjustment evaluations) of this section and the petitioner has failed to provide the requested information, Staff may deny the petition.

§ 385.1109 Orders. (Rule 1109.)

(a) Staff will issue a decision and an order granting or denying the petition in whole or in part. The order will articulate the basis for the decision, noting any dispute with the factual assertions of the petitioner.

(b) In addition to service otherwise required under this subpart, Staff will serve the decision and order on the persons who sought and were denied an opportunity to participate in the proceeding under this subpart.

(c) If Staff fails to issue an order granting or denying the petition for adjustment within the determination period, the petitioner may treat the application as having been denied and may, within 30 days after the close of the determination period, request review thereof as prescribed in Rule 1110(a) (review of denials). For purposes of this paragraph, "determination period" means the 150 days commencing with the filing of the petition, unless Staff for good cause extends such period.

(d) An order of Staff issued under paragraph (a) of this section granting an adjustment, in whole or in part, is final 30 days after it is issued, unless, during such 30-day period:

(1) A petition for review is filed under Subpart J of this subchapter in accordance with Rule 1110(a) (review of denials) in which case the order is final when the review process under Subpart J has been completed; or

(2) The Commission directs that the order be reviewed under Subpart J in accordance with Rule 1110(b), in which case when the review process under Subpart J has been completed unless the Commission expressly states that the order shall be effective pending review proceeding.

§ 385.1110 Review of initial decision and order for adjustment. (Rule 1110.)

(a) *General rule.* (1)Within 30 days after the issuance by Staff of an order granting or denying, in whole or in part, a petition for adjustment relief under this subpart, a person may file a petition for Commission review of that order in accordance with Subpart J of this subchapter, if the person:

(i) Is aggrieved or adversely affected by that order; and

(ii) Participated, or sought and was denied an opportunity to participate, in the proceeding under this subpart.

(2) Except as otherwise provided in this paragraph, the provisions of Subpart J shall apply to Commission review of both grants and denials of adjustment applications under this subpart.

(i) "Contested order" in Subpart J means the order issued by Staff granting or denying, in whole or in part, a petition for adjustment under this subpart.

(ii) "Staff" is substituted for "Secretary" in Subpart J. With respect to review of an order denying a petition for adjustment under this subpart, Staff may participate in the proceeding in the same manner prescribed for the Secretary in Rule 1005 (replies in reviews of adjustment denials). With respect to review of an order granting a petition for adjustment under this subpart, Staff may not participate in the proceeding except to the extent necessary to file the record as prescribed in Rule 1005(a)(1) (replies in reviews of adjustment denials). With respect to review of an order granting in part and denying in part a petition for adjustment under this subpart, Staff may participate as prescribed in Rule 1005(a)(1) (replies), only if a petition for review has been filed which specifically seeks review of the portion of the order denying the application for adjustment.

(3) A motion to intervene under Rule 1005(b) (interventions in adjustment proceedings) may be filed only by a person who sought and was denied an opportunity to participate, in the proceeding under this section.

(4) There is no exhaustion of administrative remedies until a request for review is filed under Subpart J in accordance with this section and the review process under Subpart J is completed by the issuance of an order granting or denying, in whole or in part, the relief requested.

(b) *Review initiated by the Commission.* Within 30 days after the issuance by Staff of an order granting, in whole or in part, a petition for adjustment relief under this subpart, the Commission may direct that the order be reviewed in a proceeding which, insofar as practicable, will conform to proceedings under Subpart J. The order directing such review will specify the manner in which such proceedings will be conducted and the extent to which Subpart J apply.

(c) *Separation of functions.* Any person who participated in the proceeding to review the grant or denial of that adjustment under this Rule as a witness or counsel may not advise the Commission concerning the review of the grant or denial of that adjustment.

§ 385.1111 Conferences. (Rule 1111.)

Staff may direct that a conference be convened. The conference will be conducted by Staff in accordance with procedures Staff determines will most expeditiously further the purpose of the conference. A conference will be convened only after actual notice of the time, place and nature of the conference is provided to the parties. All parties may attend the conference. However, if a party wishes to present confidential information at the conference, Staff may exclude the other parties from that part of the conference when the confidential information is presented.

§ 385.1112 Requests for confidential treatment. (Rule 1112.)

(a) If a person filing a document under this subpart claims that some or all of the information contained in a document is exempt from the mandatory disclosure requirements of the Freedom of Information Act, or is otherwise exempt by law from public disclosure, that person may request confidential treatment of such information. At the time request is made for confidential treatment, the person must submit a copy of the document which contains the confidential information and two copies of the document which exclude the information for which confidential treatment is requested. The request for confidential treatment must describe the information deleted and specify the grounds for the claim for confidential treatment. The service requirements of Rule 2010 (service) are deemed satisfied if a copy of the document with the confidential information deleted is served.

(b) If a determination to disclose the information is made under Part 388 (public information and requests), the person who has requested confidential treatment will be given notice thereof and will be afforded no less than 10 days to respond to such determination before the information is disclosed.

§ 385.1113 Interim relief. (Rule 1113.)

(a) The petitioner may at any time file a request for interim relief in a proceeding under this subpart, setting forth the legal and factual basis for the request. Service of such request must comply with the service requirements set forth in Rule 1104(b) (initial petition of adjustment request) and must be made on each person described in such rule as well as on any other party to the proceeding.

(b) The grounds for granting interim relief are:

(1)(i) A showing that irreparable injury will result in the event the interim relief is denied; and

(ii) A showing that denial of the interim relief requested will result in a more immediate special hardship or inequity to the person requesting the interim relief than the consequences that would result to other persons if the interim relief were granted; or

(2) A showing that it will be in the public interest to grant the interim relief.

(c) A party may within 10 days after the filling of the request for interim relief file a reply to the request for interim relief.

(d) Staff may request a written statement of the views of a party regarding whether the interim relief should be granted and may convene an expedited conference on the request for interim relief.

(e) If Staff has not granted the request for interim relief within 30 days after it is filed, the request is denied.

(f)(1) Subject to paragraph (f)(2) of this section, Staff will issue an order granting or denying the request for interim relief and will notify the parties. Any grant of interim relief is subject to further modification in the order issued under paragraph (f)(1) of this section.

(2) The Commission may, on its own motion, at any time revoke, modify, rescind, stay or take any other appropriate action concerning the order granting interim relief.

§ 385.1114 Motions. (Rule 1114.)

A party may file a motion at any time. Motions must set forth the ruling or relief requested and must state the grounds therefor and the statutory or other authority relied upon. Staff will rule on all motions.

§ 385.1115 Procedural rulings. (Rule 1115.)

Staff may make any procedural rule or provide any procedural relief.

§ 385.1116 Appeals. (Rule 1116.)

All actions under this subpart are taken by Staff, except with respect to requests for public information under Part 388. Except as provided in Rule 1110 (review of initial adjustment decision) of this section, there are no appeals to the Commission from Staff action taken under this section.

§ 385.1117 Petition for adjustment treated as request for interpretation. (Rule 1117.)

(a) Staff may, if appropriate, treat a petition filed under Rule 1103 (petition for adjustment) as a request for an interpretation under section 502(c) of the NGPA, of that Act or rule or order issued under that Act.

(b) If the Staff exercises its discretion under paragraph (a) of this section to treat a petition for adjustment as a request for an interpretation, then:

(1) Staff will notify the parties to the proceeding that the petition is being treated as a request for an interpretation under Rule 1901; and

(2) The time limits in this section are stayed pending issuance of the interpretation.

(c) After the interpretation is issued, if the petitioner wishes to reinstate the adjustment proceeding, the petitioner may do so by notifying the Commission in writing that the petition should be reinstated.

Subpart L—[Reserved]

Subpart M—Cooperative Procedure With State Commissions

§ 385.1301 Policy. (Rule 1301.)

(a) The Federal Power and Natural Gas Acts, sections 209 and 17,

respectively, authorize cooperation between the Federal Energy Regulatory Commission and the State commissions of the several States in the Administration of said Acts, which include authorization for:

(1) Reference of any matter arising in the administration of these Acts to a board to be composed of a member or member from a State or States affected, or to be affected, by the particular matters pending before the Commission;

(2) Conferences with State commissions regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities or natural gas companies subject to the jurisdiction of such State commissions and of the Commission; and

(3) Joint hearings with State commissions in connection with any matter with respect to which the Commission is authorized to act.

(b) The matters that should be the subject of a conference referred to a board, or heard at a joint hearing of State commissions and the Commission, obviously, cannot be determined in advance. It is understood, therefore, that the Commission or any State commission will freely suggest cooperation with respect to any proceeding or matter affecting any public utility or natural gas company subject to the jurisdiction of the Commission and of a State commission, and concerning which it is believed that cooperation will be in the public interest.

§ 385.1302 Notice. (Rule 1302.)

(a) *By Commission.* (1) Whenever there is instituted before the Commission any proceeding under either the Federal Power Act or the Natural Gas Act, the State commission or commissions of the State or States affected thereby will be given notice thereof immediately by the Commission. As deemed necessary for an understanding of the subject matter, each such notice will be supplemented by copies of applications, complaints, petitions, or orders instituting proceedings. Each such notice given to a State commission will request that the Commission be notified within a reasonable time whether the proceeding is deemed one that should be considered under the cooperative provisions of this subpart, and, if so, to advise the Commission as to the nature of its interest in the matter, and further, to specify whether it desires a conference, the creation of a board, or a joint or concurrent hearing, as defined in this subpart and the reasons for such request.

(2) Any commission suggesting some form of such cooperative procedure should also state whether there is pending, or will be pending before it, a proceeding in which a concurrent hearing might appropriately be held and whether its proposal is for such hearing covering such proceeding and the proceeding pending before the Commission.

(3) A State commission recommending to the Commission reference of a proceeding to a board, under either the Federal Power Act or the Natural Gas Act, should state with fullness the reasons which led it to believe that such reference is desirable and in the public interest.

(4) Upon the receipt from a State commission of a communication suggesting cooperation, the Commission will consider the same, and may confer with the Commission making the request and with other interested commissions, if any, in such manner as may be most suitable, and, if cooperation in the manner proposed, or in any other manner, appears to be practicable and desirable, will so advise each interested State commission, and will invite it to participate therein.

(b) *By State commission.* (1) Each State commission should, in like manner, notify the Commission of any proceeding instituted before it the subject matter of which is also subject to the jurisdiction of the Commission, or in which it believes the Commission is interested. Such notice should be supplemented by copies of applications, petitions, complaints, or orders

instituting proceedings which may be necessary to an understanding of the subject matter. Such notice should include the suggestions which the State commission may wish to make concerning cooperative procedure.

(2) Upon receipt of such notice, the Commission will consider the same and will promptly notify the State commission whether or not in its opinion cooperation in the manner proposed, or in any other manner, appears to be practicable and desirable. The Commission is free to propose cooperative procedure whether or not such proposal of cooperation has been made by the State commission first giving notice of the proceeding.

(c) *Commission or State commissions to invite participation in cooperative procedure.* In the event that cooperation in a particular proceeding has been determined upon, the Commission or a State commission before which the proceeding is pending will so advise each interested State commission and will invite it to take part therein.

§ 385.1303 Conferences. (Rule 1303).

Inasmuch as experience has proved that informal conferences are the means most often used to enable commissions to work together to promote good regulation, affording means whereby common understandings may be reached, and the imposition of inconsistent or conflicting regulations upon companies subject to both Federal and State control may be avoided and means whereby State commissions may secure the assistance in State regulatory work with sections 209 and 17, respectively, of the Federal Power and Natural Gas Acts authorize the Commission to extend, any commission, Federal or State, should always feel free to suggest a conference to another commission, concerning any matter of regulation subject to the jurisdiction of either, with respect to which it is believed that a cooperative conference may be in the public interest. The Commission desiring a conference upon any such matter should notify other interested commissions without delay, and thereupon the Commission or a State commission, as may be agreed, will promptly arrange for a conference in which all interested commissions will be invited to be represented.

§ 385.1304 Procedure governing matters referred to a board. (Rule 1304.)

(a) It is believed that the statutory provisions of sections 209 and 17, respectively, of the Federal Power and Natural Gas Acts, for the reference of a proceeding to a board constituted as therein provided, were designed for use in unusual cases, an as a means of relief to the Commission when it might find itself unable to hear and determine cases before it, in the usual course, without undue delay.

(b) Whenever the Commission, either upon its own motion or upon the suggestion of a State commission or at the request of any interested party, determines that it is desirable to refer a matter arising in the administration either of the Natural Gas Act or Part II of the Federal Power Act, to a board to be composed of a member or members from the State or States affected or to be affected by such matter, the procedure will be as follows: The Commission will send a request to each interested State commission to nominate a specified number of members to serve on such board. Whenever more than one State is involved, the representation of each State concerned shall be equal, unless one or more of the States affected chooses to waive such right of equal representation. The Commission will specify the functions to be performed by such board in each instance. When the member or members of any board have been nominated and appointed in accordance with the provisions of either section 209 of the Federal Power Act or section 17 of the Natural Gas Act, the Commission will issue an order referring the particular matter to such board, and such order will fix the time and place of hearing, define the "force and effect" which an action of the board will have, the manner in which the proceedings will be conducted, and specify the allowances to be made for the expense

of the members of the board. As far as applicable, the rules of practice and procedure as from time to time adopted or prescribed by the Commission will govern such board. The board will have authority to adjourn the hearing from day to day, subpoena witnesses, rule on the relevancy, competency, and materiality of evidence, and will, after hearing all interested parties, submit its report to the Commission.

§ 385.1305 Joint and concurrent hearings. (Rule 1305.)

(a) The term "joint hearing" used in sections 209 and 17, respectively, of the Federal Power and Natural Gas Acts is understood to cover any hearing in which members of the Commission and members of one or more State commissions may sit together in a proceeding pending before one such commission, whether or not a proceeding or proceedings involving similar or corresponding issues be pending before any other commission.

(b) Two different types of proceedings have been called "joint hearings". One is that type of proceeding where members of one or more State commissions sit with members of the Commission for information or in an advisory capacity. The State commissioners in such case do not develop a record for their respective commissions and may not, at their own discretion, make a recommendation to the Commission. The other type of joint hearing is often referred to as a "concurrent hearing". Under this procedure the Commission and one or more State commissions sit together to hear and jointly make a record upon a matter over which all of the participating commissions have jurisdictions and responsibility for action.

(c) The Commission or any State commission or commissions should feel free to suggest or request a joint or concurrent hearing at any time. It is believed that the concurrent hearing is the type of cooperative hearing which is likely to be most useful and effective.

(d) Whenever a concurrent hearing has been agreed upon by the Commission and one or more State commissions, the procedure will be:

(1) Each commission will designate the representative or representatives of such commission to sit at such concurrent hearing, and will designate the representative who will be the presiding officer for such commission.

(2) It will be understood that participation in such concurrent hearing will in no way affect the complete control by each commission of the proceeding before it. It will be understood, also, that participation in either a joint or concurrent hearing will in no way preclude any commission from causing to be present in any such case pertinent evidence with respect to matters in issue.

(3) The representative designated by the Commission will be the presiding officer to announce rulings with respect to which there is no disagreement; and such rulings will be considered concurrent rulings. However, the presiding officer for any commission which does not concur in any ruling may announce a divergent ruling and such divergent ruling, whether with respect to the admissibility of evidence or any other matter, will be considered the ruling for his or her commission.

(4) The record of the concurrent hearing will be the record of each commission paricipating, except that, if divergent rulings are made, the rulings will be reported so as to separate and distinguish clearly the record of the respective participating commissions and the evidence admitted in each record, in accordance with the rulings of the respective commissions. If, in any proceeding, the ruling of one presiding officer has the effect of admitting any voluminous exhibit or testimony which is excluded by the ruling of another presiding officer, the taking of such evidence, whenever possible, will be deferred until after the completion of the proceedings which can be conducted under concurrent rulings. When such testimony is taken, the transcript of such

evidence will be made available to the participating commissions, if desired.

(5) In all respects concerning which there is no divergence of ruling, the hearing will be conducted in accordance with the rules of practice and procedure prescribed by the Commission, subject to the express understanding that each participating State commission will control its own record and make its own rulings as to the admissibility of evidence and as to other matters affecting its proceedings, and will make its own separate final decision or order therein.

(e) Before either the Commission or a participating State commission will enter any order or orders in a concurrent proceeding, opportunity will be afforded for conference between the Commission and the State commissions participating.

(f) Whenever a joint hearing other than a concurrent hearing is agreed upon, the commissioners which take part therein will agree upon the procedure to be followed in such hearing in advance of the opening of the same. With respect to any concurrent hearing, a special agreement may be made by the commissions taking part therein for a procedure or action differing from that outlined in this plan.

(g) Cooperation between two or more commissions in a concurrent hearing will preclude either from taking the position of an advocate or a litigant. If a commission wishes to take such a position, it will not be cooperating participant in that proceeding. In such situation the appropriate method of procedure will be intervention under Rule 214.

§ 385.1306 Intervention by State commissions. (Rule 1306.)

Any interested State commission may, as a matter of right, intervene in any proceeding before the Federal Energy Regulatory Commission, as provided in Rule 214.

Subpart N—[Reserved]

Subpart O—[Reserved]

Subpart P—[Reserved]

Subpart Q—[Reserved]

Subpart R—[Reserved]

Subpart S—Miscellaneous

§ 385.1901 Interpretations and interpretative rules under the NGPA. (Rule 1901.)

(a) *Purpose and applicability.*—(1) *Purpose.* The purpose of this section is to provide procedures by which:

(i) A person may seek a written interpretation from the General Counsel construing a provision of the NGPA, or clarifying a rule issued by the Commission under the NGPA; and

(ii) The Commission may publish an interpretative rule that will have general applicability and effect.

(2) *Applicability.* (i) This section applies to requests under section 502(c) of the NGPA for interpretations of the NGPA or of rules or of orders, having the appliability and effect of a rule as defined in 5 U.S.C. 551(4), issued under the NGPA. It does not apply to orders issued under sections 301, 302, and 303 of the NGPA.

(ii) This section applies to requests for interpretations to prospective, existing or completed facts, acts, or transactions. Interpretations based on hypothetical facts, acts, or transactions will not be considered.

(b) *Definitions.* For the purpose of this section, the following definitions apply.

(1) "Direct participant" means any person or legal entity who is, or plans to be an actual party in the act, transaction, or circumstance presented, and who has an immediate or direct financial interest in the act, transaction, or circumstance.

(2) "Interpretation" means a written statement of the General Counsel which applies a particular rule to a particular set of facts, acts, circumstances or transactions. In the discretion of General Counsel, the interpretation may contain a detailed factual and legal

analysis, a summary of the facts or the law, or both, or it may be a conclusory statement.

(3) "Interpretative rule" means an official interpretative statement of general applicability issued by the Commission and published in the **Federal Register** that applies the NGPA or rules issued thereunder to a specific set of facts, acts, circumstances and transactions.

(4) "NGPA" means the Natural Gas Policy Act of 1978.

(5) "Request" means a request for an interpretation.

(6) "Rule" means a rule or an order having the effect of a rule as defined in 5 U.S.C. 551(4).

(c) *Persons who may request an interpretation.* (1) Any person who is or will be a direct participant in an act, transaction, or circumstance affected by the NGPA or a rule issued by the Commisson under the NGPA may file with the Office of the General Counsel a request for an interpretation.

(2) Requests for interpretations must be addressed to the Office of the General Counsel as follows:

Federal Energy Regulatory Commission, Interpretations Section, Office of the General Counsel, Suite 8000, 825 North Capitol Street, NE., Washington, D.C. 20426

(d) *Content of request.*—(1) *Facts.* A request for interpretation must contain a full and complete statement of the relevant and material facts pertaining to the act, transaction, or circumstance that is the subject of the request for interpretation. When the request pertains to only one step of a larger integrated transaction, the facts, circumstances, and other relevant information pertaining to the entire transaction must be included in the request.

(2) *Statement of the question.* The request must clearly designate the section of the statute, regulation, rule, or part thereof which the person making the request seeks to have interpreted and must set forth clearly and concisely the question for which an interpretation is sought. The request may also set forth a proposed answer to the question.

(3) *Anaylsis.* If the request proposes a particular answer:

(i) The request must set forth a legal analysis in support of the proposed answer and cite relevant authorities in support thereof.

(ii) The request must set forth the legal and business consequences which will flow from the proposed answer.

(4) *Factual statements.* (i) The request must be accompanied by a statement that to the best of the applicant's personal information, knowledge, and belief there is no untrue statement of a material or relevant fact and there is no omission of a material or relevant fact made in the request.

(ii) Any untrue statement or omission of a material or relevant fact upon which the Office of the General Counsel relied in a request for an interpretation is deemed to be a statement or entry under section 1001 of Title 18, *United States Code.*

(5) *Notification of other parties.* (i) A person submitting a request must specify each person who is a direct participant in the circumstance, act or transaction; must notify them in writing of the request for an interpretation; and must send them a copy of such request. Such notification and the addresses of the persons notified must be included in a request to the General Counsel.

(ii) Each person notified pursuant to paragraph (d)(5)(i) of this section may submit information regarding any fact provided in the request of which it has personal knowledge, if such fact is different from the facts presented by the applicant. Such fact must be presented to the Office of the General Counsel as set forth in paragraph (d)(4) of this section.

(e) *Additional information.* The General Counsel may request additional information, documentation or legal analysis in connection with any request for any interpretation.

(f) *Referral of information.* Information submitted in a request for interpretation may be used by the

Commission or its Staff in their official capacity. Any information received will be placed in a public file in the Commission's Office of Public Information.

(g) *The interpretation.* (1) Except as provided in paragraph (g)(2) of this section, the General Counsel will provide a copy of his or her written interpretation of the NGPA or rule as applied to the act, transaction, or circumstance presented upon the person who made the request for the interpretation and upon persons named in the request as direct participants in the act, transaction, or circumstance.

(2) The General Counsel may determine not to issue an interpretation, in which case the person who made the request and direct participants as specified in the request will be notified in writing of the decision not to issue an interpretation, and the reason for the decision.

(3) Only those persons to whom an interpretation is specifically addressed and other persons who are named in the request, who have been informed by the applicant for an interpretation of the pendency of the request and who are direct participants in the act, transaction or circumstance presented, may rely upon it. The effectiveness of an interpretation depends entirely on the accuracy of the facts presented to the General Counsel. If a material or relevant fact has been misrepresented or omitted or if any material or relevant fact changes after an interpretation is issued or if the action taken differs from the facts presented in the request, the interpretation may not be relied upon by any person.

(4) An interpretation may be rescinded or modified prospectively at any time. A rescission or modification is effected by notifying persons entitled to reply on the interpretation at the address contained in the original request.

(5) Any interpretation based on the NGPA or a rule issued thereunder in effect at the time of issuance may be relied upon only to the extent such law or rule remains in effect.

(6) Except as provided in paragraph (g)(3), (g)(4) and (g)(5) of this section, the Staff will not recommend any action to the Commission which is inconsistent with the position espoused in the interpretation. The interpretation of the General Counsel is not the interpretation of the Commission. An interpretation provided by the General Counsel is given without prejudice to the Commission's authority to consider the same or like question and to issue a declaratory order to take other action which has the effect of rescinding, revoking, or modifying, the interpretation of the General Counsel.

(h) *Appeal and judicial review.* There is no appeal to the Commission of an interpretation.

(i) *Interpretative rules.* Upon the petition of any person or upon its own motion, the Commission may publish in the **Federal Register** an interpretative rule regarding any question arising under the NGPA or a rule promulgated thereunder. Any person is entitled to rely upon an interpretative rule.

(j) *Applications for adjustments treated as requests for interpretations.* Except for the notification provisions of paragraph (d)(5) of this section, the provisions of this section apply to any petition for an adjustment which is deemed a request for an interpretation under Rule 1117. Notice to all parties to an adjustment proceeding under Subpart K of this part that is deemed to be a request for an interpretation will be given under Rule 1117(d)(1).

§ 385.1902 Appeals from action of staff. (Rule 1902.)

Any staff action, other than a decision or ruling of presiding administrative law judge, taken pursuant to authority delegated to the staff by the Commission that would be final, but for the provisions of this section, may be appealed to the Commission by an interested person. The challenged staff action may be appealed by filing a petition within 30 days of the action. Answers to such petitions may be filed by any party within 10 days of service of the petition. An appeal from any ruling

of a presiding administrative law judge will conform to the requirements of Rule 715 (interlocutory appeals to the Commission from rulings of presiding officers). The Commission considers that a petition for appeal from action taken by the staff is deemed denied if not acted upon by the Commission within 30 days after the filing of such petition. The Commission further considers its action on appeals made pursuant to this paragraph to be final agency action that is subject to a request for rehearing under Rule 713 (request for rehearing).

§ 385.1903 Notice in rulemaking proceedings. (Rule 1903.)

Before the adoption of rule of general applicability or the commencement of hearing on such a proposed rulemaking, the Commission will cause general notice to be given by publication in the **Federal Register**, such notice to be published therein not less than 15 days prior to the date fixed for the consideration of the adoption of a proposed rule or rules or for the commencement of the hearing, if any, on the proposed rulemaking, except where a shorter period in reasonable and good cause exists therefore: *Provided however*, That:

(a) When the Commission, for good cause, finds it impracticable, unnecessary, or contrary to the public interest to give such notice, it may proceed with the adoption of rules without notice by incorporating therein a finding to such effect and a concise statement of the reasons therefore;

(b) Except when notice or hearing is required by statute, the Commission may issue at any time rules of organization, procedure or practice, or interpretative rules, or statements of policy, without notice or public proceedings; and

(c) This section is not to be construed as applicable to the extent that there may be involved any military, naval, or foreign affairs function of the United States, or any matter relating to the Commission's management or personnel, or to United States property, loans, grants, benefits, or contracts.

§ 385.1904 Copies of transcripts. (Rule 1904.)

The Commission will cause to be made a stenographic record of public hearings and such copies of the transcript thereof as it requires for its own purposes. Participants desiring copies of such transcript may obtain the same from the official reporter upon payment of the fees fixed therefor.

§ 385.1905 Subpoenas. (Rule 1905.)

(a) *Issuance.* Subpoenas for the attendance of witnesses or for the production of documentary evidence, unless directed by the Commission, will issue only upon petition in writing to the Commission or the presiding officer, except that during sessions of a hearing in a proceeding, such petition may be made orally on the record before the Commission or presiding officer, who is hereby given authority to determine the relevancy and materiality of the evidence sought and to issue such subpoenas in accordance with such determination. Such written petitions must be verified and must specify as nearly as may be the general relevance, materiality, and scope of the testimony or documentary evidence sought, including, as to documentary evidence specification as nearly as may be, of the documents desired and the facts to be proved by them in sufficient detail to indicate the materiality and relevance of such documents.

(b) *Service and return.* If service of subpoena is made by a United States marshal or deputy thereof, such service will be evidenced by the return of service. If made by another person, such person must make affidavit, describing the manner in which service was made, and must return such affidavit on or with the original subpoena. In case of failure to make service, the reasons for the failure must be stated on the original subpoena. In making service, a copy of the subpoena must be exhibited to and left with the person to be served. The original supoena, bearing or

accompanied by the authorized return, affidavit, or statement must be returned forthwith to the Secretary or, if so desired on the subpoena, to the presiding officer before whom the person named in the subpoena is required to appear.

(c) *Fees of witnesses.* Witnesses who are subpoenaed will be paid fees as provided in Rule 510(e) (relating to fees).

§ 385.1906 Depositions. (Rule 1906.)

(a) *When permissible.* The testimony of witness may be taken by deposition, upon application by a participant in a proceeding pending before the Commission, at any time before the hearing is closed, upon approval by the Commission or the presiding officer.

(b) *Notice and application.* Unless notice is waived, no deposition will be taken except after at least 10 days' notice to the parties within the United States, and 15 days' notice when a deposition is to be taken elsewhere. Such notice must be given in writing by the participant proposing to take such deposition or by his or her attorney to the other participants or their attorneys of record and to the Commission. In such notice and application to take evidence by deposition, the participant desiring to take the deposition must state the name and post office address of the witness, the subject matter concerning which the witness is expected to testify, the time and place of taking the deposition, the name and post office address of the officer before whom it is desired that the deposition be taken, and the reason why such deposition should be taken. The other participants may, within the time stated in this section, make any appropriate response to such notice and application.

(c) *Authorization for taking.* Thereupon, if the application so warrants, the Commission or presiding officer, will issue and serve, within a reasonable time in advance of the time fixed for taking testimony, upon the participants or their attorneys an authorization naming the witness whose deposition is to be taken and the time, place and officer before whom the witness is to testify, but such time, place and officer so specified may or may not be the same as those named in the said notice and application.

(d) *Officer before whom taken*—(1) *Within the United States.* Such depositions may be taken before a member, a presiding officer or other authorized representative of the Commission, any judge, commissioner, or clerk of any court of the United States, any chancellor, judge, or justice of a State court, any mayor or chief magistrate, or a city, or any notary public, not being counsel or attorney for any of the participants, or interested in the proceeding or investigation, according to such designation as may be made in the authorization.

(2) *In foreign countries.* Where such deposition is taken in a foreign country, it may be taken before a secretary of an embassy or legation, counsel general, counsel, vice consul, or consular agent of the United States, or before such person or officer as may be designated in the authorization or agreed upon by the parties by stipulation in writing filed with and approved by the Commission or the presiding officer. The magistrate, person, or officer so deignated in this section will be referred to as the Officer.

(e) *Oath and reduction to writing.* Every person whose testimony is taken by deposition will be sworn, or will affirm concerning the matter about which he or she shall testify, before any questions are put or testimony given. The testimony will be reduced to writing by, or at the direction of, the officer, after which the deposition will be subscribed by the witness and certified in the usual form by the officer. Unless otherwise directed in the authorization, after the disposition has been subscribed and certified, it will be forwarded, together with the number of copies specified in the authorization, the copies being made by, or at the direction of, such officer by such officer in a sealed envelope addressed to the Commission at its office in Washington, D.C., with sufficient postage affixed. Upon receipt thereof, the Secretary shall file the original in the proceeding and will forward a copy to each party or his

or her attorney of record and to staff counsel.

(f) *Copies.* Rule 2004 (copies of filings) is not applicable with respect to the number of copies to be provided.

(g) *Scope and conduct of examination.* Unless otherwise directed in the authorization, the deponent may be examined regarding any matter which is relevant to the issues involved in the pending proceeding, including the existence, description, nature, custody, condition, and location of any books, documents or other tangible things, and the identity and location of persons having knowledge of relevant facts. Parties or their attorneys and staff counsel will have the right of cross-examination, objection and exception to questions or evidence, the grounds relied upon will be noted by the officer upon the deposition, but he does not have power to decide on the competency or materiality or relevancy of evidence. Objections to questions or evidence not taken before the officer are deemed to be waived.

(h) *Not part of record unless received in evidence.* No part of a deposition will constitute a part of the record in the proceeding, unless received in evidence by the Commission or presiding officer. Objection may be made at the hearing in the proceeding to receiving in evidence any disposition or part thereof for any reason which would require the exclusion of the evidence if the witnesses were then present and testifying.

(i) *Fees of officers and deponents.* Deponents whose depositions are taken and the officers taking the same are entitled to the same fees as are paid for like services in the District Courts of the United States, which fees must be paid by the party or participant at whose instance the depositions are taken.

§ 385.1907 Reports of compliance. (Rule 1907.)

When any licensee, permittee, or any other person subject to the jurisdiction of Commission is required to do or perform any act by Commission order, permit, or license provision, there must be filed with the Commission within 30 days following the date when such requirement became effective, a notice, under oath, stating that such requirement has been met or complied with: *Provided, however,* That the Commission, by rule or order, or by making specific provision therefor in a license or permit, may provide otherwise for the giving of such notice of compliance. Five conformed copies of such notice must be filed in lieu of the fourteen conformed copies required by Rule 2004 (copies of filings).

Subpart T—Formal Requirements for Filings in Proceedings Before the Commission

§ 385.2001 Filings. (Rule 2001.)

(a) *Filings with the Commission.* Unless otherwise provided in this chapter, a filing required to be made with the Commission must be submitted to the Secretary either (A) by mailing the document to: Secretary, Federal Energy Regulatory Commission, 825 N. Capital Street, NE., Washington, D.C. 20426, or (B) by hand delivering the document to: Room 3110, 825 N. Capitol Street, NE., Washington, D.C. A document is considered filed on the date stamped by the Secretary, unless subsequently rejected. Documents received after regular business hours are considered to have been filed on the next regular business day.

(b) *Rejection.* (1) Failure of a filing to comply with all or part of a statute or Commission rule or order may be grounds for rejection of the filing, unless it is accompanied by a motion requesting a waiver of such requirement and the motion is granted. If rejected, a filing is deemed not to have been filed with the Commission.

(2) Filings rejected under paragraph (b)(1) of this section are returned by the Secretary, or the office director to whom the filing has been referred, with an indication of the deficiencies thereof and the reasons for rejection and return.

(3) Failure to reject a filing under paragraph (b)(1) of this section does not waive the obligations to comply with the

requirements of this chapter. Failure to comply with such requirement may be cause for striking all or part of a filing.

§ 385.2002 Caption of filings. (Rule 2002.)

Each filing must be headed with a caption that sets forth:

(a) The docket designation, if any;

(b) The title of the proceeding (a shortened designation may be used);

(c) A heading describing of the filing; and

(d) The name of the participant on whose behalf the filing is made (a shortened designation may be used).

§ 385.2003 Specifications. (Rule 2003.)

(a) *Paper.* A filing with the Commission must be typewritten, printed, or reproduced, with each copy clearly legible, on letter size, unglazed paper, 8 to 8½ inches wide by 10½ to 11 inches long, except that a log, graph, map, drawing, or chart will be accepted on larger paper if it cannot be legibly provided on letter size paper.

(b) *Format.* A filing must be double-spaced with left margins not less than 1 inch wide, and with each quotation in excess of 50 words indented and single-spaced. If a filing exceeds one page, it must be bound or stapled, at the left side only. If a filing is printed, it must be printed in not less than 10 point type with double-leaded text and single-leaded quotations.

§ 385.2004 Copies of filings. (Rule 2004.)

An original of each filing with the Commission must be accompanied by fourteen exact copies, unless a different number is required by statute or Commission rule or order. A waiver of this requirement may be requested by motion.

§ 385.2005 Subscription and verification. (Rule 2005.)

(a) *Subscription.* (1) Each filing with the Commission must be signed. The signature constitutes a certificate that the signer has read the filing being signed and knows its contents, that the contents are true as stated to the best knowledge and belief of the signer, and that the signer possesses full power and authority to sign the filing.

(2) A filing may be signed:

(i) By the person making the filing;

(ii) If signed on behalf of a corporation, trust, assocation, or other organized group, by an officer of the organization;

(iii) If signed on behalf of any governmental authority, agency, or instrumentality, by an officer or employee thereof; or

(iv) By a representative qualified to practice before the Commission under Rule 2101 (appearance and practice before the Commission) and who possesses authority to sign. The signer may be required to submit evidence of authority to sign the filing.

(b) *Verification.* Unless verification is specifically required by this chapter, no facts alleged in a filing with the Commission need be verified. If verification is required, such verification is under oath or affirmation by a person having knowledge of the matters set forth therein. If the verification is made by anyone other than the signer, a statement must be added to the verification stating the reason for the variation.

§ 385.2006 Docket system. (Rule 2006.)

The Secretary will maintain a system for docketing proceedings. The public information in a docket is available for inspection and copying by the public during the office hours of the Commission insofar as is consistent with the proper discharge of the Commission's duties and in conformity with Part 388 (public information and requests).

§ 385.2007 Time. (Rule 2007.)

(a) *Computation.* Except as otherwise required by law, any period of time prescribed or allowed by statute or Commission rule or order is computed to exclude the day of the act or event from which the time period begins to run. The last day of the period is included, unless it is a Saturday, Sunday, or legal public holiday as designated in section 6103 of title 5, United States Code (5 U.S.C. 6103), in which case the period does not

end until the close of the next day which is not a Saturday, Sunday, or legal public holiday. Part-day holidays are counted as normal business days.

(b) *Issuance of Commission rules or orders.* The date and time of issuance of a Commission rule or order is the earlier of the date and time the Secretary (1) posts a full-text copy in the Division of Public Information, (2) mails or delivers copies of the order to the parties, or (3) makes such copies public. The date of issuance will appear on each order, but it need not be the date upon which the rule or order is adopted by the Commission.

(c) *Effective date of Commission rules or orders.* Unless otherwise ordered by the Commission, Commission rules or orders are effective on the date of issuance. An initial decision issued by a presiding officer is effective at such time as it becomes final under Rule 708(d) (the date an initial decision becomes final).

§ 385.2008 Extension of time. (Rule 2008.)

Except as otherwise provided by law, whenever an act is required or allowed to be done at or within a specified time, the time prescribed may be extended by the decisional authority for good cause, upon a motion made before the expiration of the period prescribed or as previously extended. If a motion for extension of time is made after the expiration of the specified period, the act may be permitted to be done where extraordinary circumstances are shown adequately justifying the failure to act in a timely manner.

§ 385.2009 Notice. (Rule 2009.)

Unless actual notice is given, notice by the Commission is to be given by publication in the **Federal Register** by the Secretary. Actual notice is usually given by service under Rule 2010 (service of documents).

§ 385.2010 Service. (Rule 2010.)

(a) *By participants.* (1) A participant who files a document in a proceeding must serve a copy of it upon each person whose name is on the official service list (or applicable restricted service list) for the proceeding or phase thereof, and upon any other person who is required to be served by the Commission rule or order or as otherwise required by law.

(2) A person who receives a rejection letter or deficiency letter from the Commission must serve a copy of such letter on those to whom the person had served copies of the filing to which the rejection letter or deficiency letter relates.

(b) *By the Secretary.* The Secretary will serve a copy of a complaint, notice of tariff or rate examination, or order to show cause upon each person to whom a complaint is directed or to whom such notice or order is issued. The Secretary also will serve a copy of any rule or order by a decisional authority in a proceeding upon each person whose name is on the official service list (or applicable restricted service list) for the proceeding or phase thereof.

(c) *Official service list.* The official service list for a proceeding will contain the names and addresses of the persons designated for service in the first pleading (other than a protest) or tariff or rate filing filed by each participant. The official service list also will contain the name of counsel for the staff of the Commission. The designation of a person for service may be changed by a written notice to the Commission served on each person whose name is on the official service list.

(d) *Restricted service list.* The Secretary, an office director, or the presiding officer may establish, by order, a restricted service list for the purpose of eliminating unnecessary expense or improving administrative efficiency. A restricted service list may be established for an entire proceeding, a phase of a proceeding, one or more issues in a proceeding, or one or more cases in a consolidated proceeding. A restricted service list contains the names of the persons on the official service list who, in the judgment of the decisional authority establishing the list, are the active participants or their representatives with respect to such

proceeding, phase of a proceeding, issue in a proceeding, or consolidated proceeding. A restricted service list is maintained in the same manner as, and in addition to, the official service list maintained in accordance with paragraph (c) of this section. Before a restricted service list is established, each person whose name is on the official service list will be given notice of the proposal to establish a restricted service list and the opportunity to show why such person should be included on the restricted service list or why a restricted service list should not be established. The designation of a person for service on a restricted service list may be changed by written notice to the Commission served on each person whose name is on the applicable restricted service list.

(e) *Interveners.* (1) If a motion to intervene or notice of intervention is filed within the prescribed time period, the names and addresses of the persons designated for service in the motion or notice are placed on the official service list (or applicable restricted service list.) After the motion or notice is filed, these persons are entitled to service in accordance with this section. However, the names and addresses of such persons are removed from the official service list if a motion is denied.

(2) If a motion to intervene is not filed within the prescribed period, the names and addresses of the persons designated for service in the motion are placed on the official service list (or other applicable restricted service list) after the motion is granted. Late interveners are served with only the documents that are filed after the motion is granted.

(f) *Methods.* Service must be made by mail or by actual delivery in some other manner and to a place that may reasonably be expected to provide actual and timely receipt.

(g) *Timing of service.* (1) Service is made when the document served is deposited in the mail or is actually delivered in another manner.

(2) Service of a document must be made no later than the date of the filing of the document.

(h) *Certification.* When a document that must be served is filed with the Commission, it must have the original of a certificate of service attached to it. Each copy of the document filed with the Commission must have a copy of the certificate of service attached to it. The certificate must conform to the following:

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list [or the restricted service list, if applicable] compiled by the Secretary in this proceeding.
Date at ———— this ———— day of ————, 19——.
Signature ————
Counsel for ————
(if applicable) ————
Address ————
Telephone number ————

Subpart U—Appearance and Practice Before the Commission

§ 385.2101 Appearances. (Rule 2101.)

(a) A participant may appear in a proceeding in person or by an attorney or other qualified representative. An individual may appear in his or her own behalf, a member of a partnership may represent the partnership, a bona-fide officer of a corporation, trust, association or organized group may represent the corporation, trust association or group, and an officer or employee of a State commission, of a department or political subdivision of a State or other governmental authority, may represent the State commission or the department or political subdivision of the State or other governmental authority, in any proceeding.

(b) A person compelled to appear or voluntarily testifying or making a statement before the Commission or the presiding officer, may be accompanied, represented, and advised by an attorney or other qualified representative.

(c) A person appearing before the Commission or the presiding officer

must conform to the standards of ethical conduct required of practitioners before the Courts of the United States, and where applicable, to the requirements of section 12(i) of the Public Utility Holding Company Act of 1935 (15 U.S.C. 791(i)).

§ 385.2102 Suspension. (Rule 2102.)

(a) After hearing the Commission may disqualify and deny, temporary or permanently, the privilege of appearing or practicing before it in any way to a person who is found:

(1) Not to possess the requisite qualifications to represent others, or

(2) To have engaged in unethical or improper professional conduct, or

(3) Otherwise to be not qualified.

(b) Contumacious conduct in a hearing before the Commission or a presiding officer will be ground for exclusion of any person from such hearing and for summary suspension for the duration of the hearing by the Commission or the presiding officer.

§ 385.2103 Appearance of former employees. (Rule 2103.)

(a) No person having served as a member, officer, expert, administrative law judge, attorney, accountant, engineer, or other employee of the Commission may practice before or act as attorney, expert witness, or representative in connection with any proceeding or matter before the Commission which such person has handled, investigated, advised, or participated in the consideration of while in the service of the Commission.

(b) No person having been so employed may within 1 year after his or her employment has ceased, practice before or act as attorney, expert witness, or representative in connection with any proceeding or matter before the Commission which was under the official responsibility of such person, as defined in 18 U.S.C. 202 while in the service of the Commission.

(c) Nothing in paragraph (a) and (b) of this section prevents a former member, officer, expert, administrative law judge, attorney, accountant, engineer, or other employee of the Commission with outstanding scientific or technological qualifications from practicing before or acting as an attorney or representative in connection with a particular matter in a scientific or technological field if the Chairman of the Commission makes a certification in writing, published in the **Federal Register**, that the national interest would be served by such action or representation.

Subpart V—Ex Parte Communications; Separation of Functions

§ 385.2201 Ex parte communications. (Rule 2201.)

In order to avoid all possibilities of prejudice, real or apparent, to the public interest and persons involved in proceedings pending before the Commission.

(a) Except as permitted in paragraph (b) of this section, no person who is a party to, or his or her counsel, agent, or other person acting on his or her behalf, and no interceder in, any on-the-record proceedings, shall submit ex-parte, off-the-record communications to any member of the Commission or of his or her personal staff, to the Administrative Law Judge, or to any other employee of the Commission, regarding any matter pending before the Commission in any contested on-the-record proceeding, and no Commissioner, member of his or her personal staff, Administrative Law Judge, or any other employee of the Commission, shall request or entertain any such ex parte, off-the-record communications. For the purposes of this section, the term "ex parte communication" means an oral or written communication relative to the merits of an on-the-record proceeding pending before the Commission which is not on the public record and with respect to which reasonable prior notice to the parties is not given, but it shall not include requests for status reports on any matter or proceeding covered by this section; the term "decisional employee" means a Commissioner or member of his or her personal staff, an administrative law judge, or any other employee of the Commission who is or may be reasonably expected to be involved in the decisional process of the

proceeding; the term "contested on-the-record proceedings" means a proceeding required by statute, constitution, published Commission rule or regulation or order in a particular case, to be decided on the basis of the record of a Commission hearing, and in which a protest or a petition or notice to intervene in opposition to requested Commission action has been filed; the term "interceder" shall include any individual outside the Commission, whether in private or public life, partnership, corporation, association, or other agency, other than a party or an agent of a party, who volunteers a communication.

(b) The prohibitions contained in paragraph (a) of this section do not apply to a communication:

(1) From an interceder who is a local, State, or Federal agency which has no official interest in and whose official duties are not affected by the outcome of the on-the-record proceedings before the Commission to which the communication relates;

(2) From an interceder relating to matters of procedure only;

(3) From a party to, or his or her counsel, agent, or other person acting on his or her behalf, in an on-the-record proceeding, if the communication relates to matters of procedure only and is directed to the Secretary of the Commission, staff counsel, or any other employee in the presence of or with the prior approval of staff counsel;

(4) From any person when otherwise authorized by law;

(5) When the communication is between the staff counsel assigned to the proceeding or, in the presence of or after coordination with such staff counsel, any other employee of the Commission (except a decisional employee) and any party or counsel to any party or parties to the proceeding or, in the presence of or after coordination with such counsel or party, and agent of any such party: *Provided,* That any employee of the Commission who may reasonably be expected to participate in the decisional process may waive such participation by entering a staff appearance in the proceeding: *Provided further,* That non-unanimous settlement offers shall therefore be served on the participants in the proceeding prior to the submission of such offers to the Commission;

(6) Which the participants agree may be made on an ex parte basis;

(7) Related to routine safety, construction, and operational inspections of project works by the Commission staff not undertaken to investigate or study a matter pending in issue before the Commission in any on-the-record proceeding;

(8) Related to routine field audits of the accounts or any books or records of a company subject to the Commission's accounting requirements not undertaken to invetigate or study a matter pending in issue before the Commission in any on-the-record proceeding;

(9) Which relates solely to a request for supplemental information or data necessary for an understanding of factual materials contained in documents filed with the Commission in a proceeding covered by this section and which is made in the presence of or after coordination with counsel, except a communication with a decisional employee, in the absence of waiver of participation;

(10) The Commission may, by rule or order, modify any provision of this subpart, or 49 CFR Part 1100, Appendix C, as it applies to all or part of a proceeding, to the extent permitted by law. The prohibitions of paragraph (a) of this section do not apply to oil pipeline proceedings which are governed by 49 CFR Part 1100, Appendix C.

(c) All written communications prohibited by paragraph (a) of this section, sworn statements reciting the substance of all such oral communications, and all written responses and sworn statements reciting the substance of all oral responses to such prohibited communications must be delivered to the Secretary of the Commission who will place the communication in public files associated with the case, but separate from the

material upon which the Commission can rely in reaching its decision. The Secretary will serve such communications upon parties to the proceeding. The Secretary will also serve a copy of the sworn statement to the communicator and allow him or her a reasonable opportunity to file a response.

(d) A Commissioner, member of his or her immediate staff, administrative law judge, or any other employee of the Commission who receives an oral office of communication prohibited by paragraph (a) of this section shall decline to listen to such communication and shall explain that the matter is pending for determination. If unsuccessful in preventing such communication, the recipient thereof shall advise the communicator that he or she will not consider the communication. The recipient shall prepare a sworn statement setting forth the substance of the communication and the circumstances thereof within 48 hours and deliver the statement to the Secretary of the Commission for compliance with the procedures established in paragraph (c) of this section.

(e) Requests for an opportunity to rebut, on the record, any facts or contentions contained in an ex parte communication which the Secretary has associated with the record may be filed in writing with the Commission. The Commission will grant such requests only where it determines that the dictates of fairness so require. Where the communication contains assertions of fact not a part of the record and of which the Commission cannot take official notice, the Commission in lieu of receiving rebuttal material normally will direct that the alleged factual assertion on any proposed rebuttal be disregarded in arriving at a decision. Nor will the Commission normally permit any rebuttal of ex parte endorsements or oppositions by civic or other organizations by the submission of counter endorsements or oppositions.

(f) Upon receipt of a communication knowingly made in violation of paragraph (a) of this section, the Commission, Administrative Law Judge, or other employee presiding at the hearing may require, to the extent consistent with the interests of justice and the policy of underlying statutes, the communicator to show cause why his or her claim or interest in the proceeding should not be dismissed, denied, disregarded, or otherwise adversely affected on account of such violation.

(g) The prohibitions contained in this section shall apply from the time at which a proceeding is noticed for hearing or the person responsible for such communication has knowledge that it will be noticed for hearing or at the time at which a protest or a motion or notice to intervene in opposition to requested Commission action has been filed, whichever occurs first.

§ 385.2202 Separation of functions of staff. (Rule 2202.)

In any proceeding in which a Commission adjudication is made after hearing, an officer, employee, or agent assigned to work upon the investigation or trial of the proceeding or to assist in the trial thereof, in that or any factually related proceeding, shall participate or advise as to the findings, conclusion or decision, except as a witness or counsel in public proceedings.

Subpart W—[Reserved]

Subpart X—[Reserved]

Subpart Y—[Reserved]

Subpart Z—[Reserved]

PART 388—PUBLIC INFORMATION AND REQUESTS

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Sec.

388.109 Procedures for requesting information.

Authority: Administrative Procedure Act, 5 U.S.C. 551–557; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Federal Power Act, 16 U.S.C. 791–828C, as amended; Natural Gas Act, 15 U.S.C. 717–717w, as amended; Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*; Public Utilities Act of 1978, 16 U.S.C. 2601 *et seq.*; Interstate Commerce Act, 49 U.S.C. 1 *et seq.*; E.O. 12009, 3 CFR, 1977 Comp., p. 142.

PART 388—PUBLIC INFORMATION AND REQUESTS

§ 388.101 Definitions.

For purposes of this part,

(a) "Filings and submittals" include:

(1) Applications, declarations, complaints, petitions, and other papers seeking Commission action;

(2) Financial and statistical and other reports to the Commission, power system statements of claimed cost of licensed projects, original cost and reclassification studies, proposed accounting entries, certificates of notification (under section 204(e) of the Federal Power Act), rates or rate schedules and related data and concurrences, and other filings and submittals to the Commission in compliance with the requirement of any statute, executive order, or Commission rule, regulation, order, license, or permit;

(3) Answers, replies, responses, objections, protests, motions, stipulations, exceptions, other pleadings, notices, depositions, certificates proofs of service, transcripts of oral arguments, and briefs in any matter or proceeding; and

(4) Exhibits, attachments and appendices to, amendments and corrections of, supplements to, or transmittals or withdrawals of, any of the foregoing.

(b) "Matter or proceeding" means the Commission elucidation of the relevant facts and applicable law, consideration thereof, and action thereupon with respect to a particular subject within the Commission's jurisdiction, initiated by a filing or submittal or a Commission notice or order.

(c) "Formal record", includes in addition to the filings and submittals in a matter or proceeding, notice or Commission order initiating the matter or proceeding and, if a hearing is held, the following: The designation of the presiding officer, transcript of hearing, exhibits received in evidence, exhibits offered but not received in evidence, offers of proof, motions, stipulation, subpoenas, proofs of service, references to the Commission, and determinations made by the Commission thereon, certifications to the Commission, and anything else upon which action of the presiding officer or the Commission may be based; it does not include proposed testmony or exhibits not offered or received in evidence.

(d) "Staff papers" include the Commission staff's working notes papers, records, memoranda, and correspondence, except:

(1) A paper not relating to a proposed settlement or to an application, permission, filing, or submittal under § 35.13, or § 154.66, of this chapter, which are intended for the Commission's consideration and are within the terms of § 388.105(d) of this part (public records) and paragraph (e) of this section, because received by the Commission in a matter or proceeding after hearing has commenced and before final Commission action; and

(2) Paper made a part of the public rules and records by inclusion in a formal record or in Commission memorandum or correspondence which is part of the public files and record.

(e) "Commission memoranda" include written communications from the staff or a presiding officer which are intended for the Commission's consideration and those to the staff or a presiding officer which are signed or transmitted by or on behalf of the Chairman, a Commissioner, the Secretary, or the Executive Director.

(f) "Commission correspondence" includes written communications and enclosures received from others than the

staff and intended for the Commission or sent to others than the staff and signed by the Chairman, a Commissioner, the Secretary, the Executive Director, or other authorized official, except those which are purely personal.

§ 388.102 Scope.

This part prescribes the rules governing public notice of proceedings, publication of decisions, and public records of the Commission.

§ 388.103 Notice of proceedings.

(a) Public sessions of the Commission for taking evidence or hearing argument and public conferences and hearings before a presiding officer, including substantive rulemaking proceedings, will not be held except upon due notice.

(b) Notice of applications, complaints, and petitions, is governed by Rule 2009 (notice). Notice of applications for certificates of public convenience and necessity under section 7 of the Natural Gas Act is governed by § 157.9 of this chapter (notice of application). Notice of public sessions and proceedings and of meetings of the Commission is governed by Rule 2009 (notice). Notice of hearings and of initiation or pendency of rulemaking proceedings is governed by Rule 1903 (notice in rulemaking proceedings). Notice of applications under Part I of the act for preliminary permits and licenses is governed by §§ 4.31 and 4.81 of this chapter (acceptance or rejection and contents). Notice of proposed alterations or surrenders of license under section 6 of the Federal Power Act may be given by filing and publication in the **Federal Register** as stated in Rule 1903 (notice in rulemaking proceedings), and, where deemed desirable by the Commission, by local newspaper advertisement.

Notice of rates charged and changes therein is governed by the filing requirements of Subchapters B and E of this chapter (regulations under the Federal Power Act and Regulations under the Natural Gas Act). Other notice required by statute, rule, regulation, or order, or deemed desirable, may be given by filing and publication in the **Federal Register** as governed by Rule 1903 (notice in rulemaking proceedings) or by service as governed by Rule 2010 (service).

§ 388.104 Notice and publication of decisions, rules, statements of policy, organization, and operations.

Service of intermediate and final decisions upon parties to the proceedings is governed by Rule 2010 (service). Descriptions of the Commission's organization, its methods of operation, statements of policy and interpretations, procedural and substantive rules, and amendments thereto will be filed with and published in the **Federal Register**. Commission opinions together with accomplish orders, Commission orders, and intermediate decisions will be released to the press and made available to the public promptly. Copies of Commissions opinions, orders in the nature of opinions, rulemaking and selected procedural orders, and intermediate decisions which have become final are published in the *Federal Energy Regulatory Commission Reports* and may be procedured from the Superintendent of Documents, United States Government Printing Office, Washington, D.C. 20402, upon payment of prescribed charges.

§ 388.105 Public records.

(a) The public records of the Commission, available for inspection and copying upon request reasonably describing the documents during regular business hours in the public reference room maintained by the Division of Public Information, include:

(1) Submittals and filings as follows:

(i) Applications, declarations, complaints, petitions, and other papers seeking Commission action;

(ii) Financial, statistical, and other reports to the Commission, power system statements of claimed cost of licensed projects, original cost and reclassification studies, proposed accounting entries, certificates of

notification (under section 204(e) of the Federal Power Act), rates or rate schedules and related data and concurrences, and other filings and submittals to the Commission in compliance with the requirement of any statute, executive order, or Commission rule, regulation, order, license, or permit;

(iii) All answers, replies, responses, objections, protests, motions, stipulations, exceptions, other pleadings, notices, depositions, certificates, proof of service, transcripts or oral arguments, and briefs in any matter or proceeding;

(iv) Exhibits, attachments and appendices to, amendments and corrections of, supplements to, or transmittals or withdrawals of, any of the foregoing; and

(v) Commission correspondence relating to the foregoing;

(2) All other parts of the formal record in any matter or proceeding set for formal or statutory hearing and any Commission correspondence related thereto;

(3) Proposed testimony or exhibit filed with the Commission but not yet offered or received in evidence.

(4) Presiding officer actions, correspondence, and memoranda to or from others, with the exception of internal communications within the Office of Administrative Law Judges;

(5) Commission orders, notices, findings, opinions, determinations, and other actions in matter or proceeding and Commission minutes which have been approved;

(6) Commission correspondence relating to any furnishing of data or information, except to or by another branch, department, or agency of the Government;

(7) Commission correspondence with respect to the furnishing of data, information, comments, or recommendations to or by another branch, department, or agency of the Government where furnished to satisfy a specific requirement of a statute or where made public by that branch, department or agency;

(8) Commission correspondence and reports on legislative matters under considerations by the Office of Management and Budget or Congress, but only after made public or released for publication by that Office or the Committee or Member of Congress involved;

(9) Staff reports on statements of claimed cost by licensees when such reports have been served on the licensee;

(10) Commission correspondence on interpretation of the Uniform System of Accounts and letters on such interpretation signed by the Chief Accountant and sent to others than the Commission, a Commissioner, or the staff;

(11) Commission correspondence on the interpretation or applicability of any statute, rule, regulation, order, license, or permit issued or administered by the Commission and letters of opinion on that subject by the General Counsel and sent to others than the Commission, a Commissioner, or the staff;

(12) Copies of the filings, certifications, pleadings, records, briefs, orders, judgments, decrees, and mandates in court proceedings to which the Commission is a party and the correspondence with the courts or clerks of court;

(13) The Commission's Administrative and Operating Manual;

(14) Trancripts, electronic recordings, or minutes of Commission meetings closed to public observation containing material nonexempt pursuant to Subpart B of Part 375 of this chapter (Government in the Sunshine Act rules);

(15) Other records of the Commission except those which are:

(i) Specifically authorized under criteria established by an Executive order to be kept secret in the interest of national defense or foreign policy and are in fact properly classified pursuant to such Executive Order.

(ii) Related solely to the internal personnel rules and practices of any agency;

(iii) Specifically exempted from disclosure by statute (other than 5 U.S.C. 552(b): *Provided,* That such statute:

(A) Requires that the matters be withheld from the public in such a manner as to leave no discretion on the issue, or

(B) Establishes particular criteria for withholding or refers to particular types of matters to be withheld;

(iv) Trade secrets and commercial or financial information obtained from a person and privileged or confidential;

(v) Interagency or intra-agency memoranda or letters which would not be available by law to a party other than an agency in litigation with the agency;

(vi) Personnel and medical files and similar files the disclosure of which would constitute a clearly unwarranted invasion of personal privacy;

(vii) Investigatory records compiled for law enforcement purposes, but only to the extent that the production of such records would interfere with enforcement proceedings, deprive a person of a right to a fair trial or an impartial adjudication, constitute an unwarranted invasion of personal privacy, disclose the identify of a confidential source and, in the case of a record compiled by a criminal law enforcement authority in the course of a criminal investigation, or by an agency conducting a lawful national security intelligence investigation, confidential information furnished only by the confidential source, disclose investigative techniques and procedures, endanger the life or physical safety of law enforcement personnel; or

(viii) Geological and geophysical information and data, including maps, concerning wells;

(16) Any reasonable segregable portion of a record after deletion of the portions which are exempt under this section.

(b) The following are examples of information which are not part of the public records of the Commission:

(1) Files and records containing facts or information not permitted to be divulged by section 301 of the Federal Power Act or section 8 of the Natural Gas Act because knowledge thereof was gained during the course of examination of books, records, data, or accounts pursuant to those sections and divulgence thereof has not been ordered by the Commission;

(2) Files and records classified under Executive Order No. 10501, 3 CFR, 1949–53 Comp., p. 979, for national security purposes;

(3) Written communications between or among the Commission, members of the Commission, the Secretary, and expressly designated members of the staff while particularly assigned, in accordance with all applicable legal requirements, to aid the Commission in the drafting of any order and findings, with or without opinion in any matter or proceeding; and

(4) Unaccepted offers of settlements in any matter or proceeding unless or until made public by act of the offeror.

§ 388.106 Index of Commission actions.

The Division of Public Information maintains and makes available for public inspection and copying current indexes providing identifying information for the public as to any matter issued, adopted, or promulgated after July 4, 1967, and required by this part to be made available or published. The index will be published quarterly and copies or supplements thereto will be distributed by sale or otherwise.

§ 388.107 Timetables and procedure in event of withholding of public records.

(a)(1) The Director of Public Information will determine within 10 days after receipt of a request for public records whether to comply with such request and will immediately notify the person making such request of such determination and the reasons therefor, and of the right of such person to appeal any adverse determination in writing to the Chairman.

(2) Requests filed pursuant to this part must be in writing, addressed to the Director of Public Information, and clearly marked "Freedom of Information Request." Request for information received by the Commission not addressed and marked as indicated in paragraph (a)(2) of this section will be

so addressed and marked by Commission personnel as soon as it is properly identified and forwarded immediately to the Director of Public Information. Requests made pursuant to this paragraph will be considered to be received upon actual receipt by the Director of Public Information.

(b)(1) The Chairman, in his or her capacity as administrative head of the agency pursuant to section 401(c) of the DOE Act, will make a determination with respect to any appeal within 20 days after the receipt of such appeal. If on appeal, the denial of the request for records is in whole or in part upheld, the Chairman will notify the person making such request of the provisions for judicial review of that determination.

(2) Appeals filed pursuant to this section must be in writing, addressed to the Chairman of the Commission, and clearly marked "Freedom of Information Appeals." Such an appeal received by the Commission not addressed and marked as indicated in this paragraph will be so addressed and marked by Commission personnel as soon as it is properly identified and forwarded immediately to the Chairman. Appeals taken pursuant to this paragraph will be considered to be received, upon actual receipt by the Chairman.

(c) In unusual circumstances, the time limits prescribed in this section may be extended by the Secretary by written notice to the person making such request setting forth the reasons for such extension and the date on which a determination is expected to be dispatched. No such notice will specify a date that would result in an extension for more than 10 working days in the aggregate. One 10-day extension may be invoked at the initial stage or at the appellate stage, or divided between the two, so long as the total extended time does not exceed 10 working days with respect to a particular request. The Secretary will be responsible for allocating distribution of the 10 days on a case-by-case basis. "Unusual circumstances" as used in this paragraph means:

(1) The need to search for and collect the requested records from field facilities or other establishments that are separate from the office processing the requests;

(2) The need to search for, collect, and appropriately examine a voluminous amount of separate and distinct records which are demanded in a single request; or

(3) The need for consultation, which will be conducted with all practicable speed, with another agency having a substantial interest in the determination of the request or among two or more components of the agency having substantial subject-matter interest therein.

(d) If the Commission fails to comply with the applicable time limit provisions of this section, the Commission can request the court for additional time to complete its review of the records by showing that exceptional circumstances exist and that it is exercising due diligence in responding to the request.

(e) Any notification of denial of any request for records under this section will set forth the names and titles or positions of each person responsible for the denial of such request.

(f) Upon any determination to comply with a request for records, the records will be made promptly available to such person making such request.

§ 388.108 Procedure in event of subpoena.

If an officer or employee of the Commission is served with a subpoena duces tecum, for material which is not part of the public file and records of the Commission shall be produced only as authorized by the Commission. Service of such a subpoena shall immediately be reported to the Commission with a statement of all relevant facts. The Commission will thereupon enter such order or give such instructions as it deems advisable.

§ 388.109 Procedures for requesting information.

Requests for information may be addressed to the Division of Public

Information of the Commission, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426. Public records are available for public inspection and copying at that office, in accordance with this part. Pleadings and other filings are filed in accordance with § 385.2001 (filings). A description of the facilities available for public reference and the procedures that may be employed to obtain information, copies of public records, or to secure informal advice and assistance from or consultation with members of the staff on problems relating to the statutes and regulations administered by the Commission is contained in § 3.8 of this chapter (information and requests).

PART 1b—RULES RELATING TO INVESTIGATIONS

4. Part 1b of Chapter I is amended as follows:

§ 1b.12 [Amended]

(a) In the last sentence of § 1b.12, by removing "§ 1.21(b) of the rules of practice," and adding in lieu thereof "§ 385.1904(b)";

§ 1b.16 [Amended]

(b) In the first sentence of § 1b.16(b), by removing "§ 1.4 of the rules of practice and procedures," and adding in lieu thereof "§ 385.2101 of this chapter";

§ 1b.16 [Amended]

(c) In the last sentence of § 1b.16(c)(4), by removing "§ 1.4 of the Commission's rules of practice, and § 1100.11 of the rules of practice of the Interstate Commerce Commission", and adding in lieu thereof "§ 385.2101 of this chapter";

§ 1b.17 [Amended]

(d) In § 1b.17, by removing "§ 1.4 of the Commission's rules of practice" and adding in lieu thereof "Subpart U of this part"

PART 2—GENERAL POLICY AND INTERPRETATIONS

5. Part 2 of Chapter I is amended as follows:

§ 2.1a [Amended]

(a) In the first sentence of § 2.1a(b), by removing "and § 1.7(e) of this Title";

§ 2.17 [Amended]

(b) In § 2.17(f), by removing "18 CFR 1.17(c)." and adding in lieu thereof "§ 385.2010(c) of this chapter";

§ 2.56a [Amended]

(c) In the first sentence of § 2.56a(g), by removing "§ 1.7(b) of the Commission's rules of practice and procedure (18 CFR 1.7(b))" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 2.56 [Amended]

(d) In § 2.56(h), by removing "§ 1.7(b) of the Commission's rules of practice and procedure (18 CFR 1.7(b))" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 2.59 [Amended]

(e) In § 2.59(a), by removing "§§ 1.8(d) and 154.27 of this chapter, *i.e.*, Rules of Practice and Procedure and Regulations, Under the Natural Gas Act respectively." and adding in lieu thereof "§ 385.214 and § 154.27 of this chapter).";

§ 2.59 [Amended]

(f) In § 2.59(e), by removing "§ 1.18 of this chapter" both times it appears and adding in lieu thereof "§ 385.601 of this chapter" in each instance;

§ 2.59 [Amended]

(g) In § 2.59(i), by removing "Notwithstanding the provisions of § 1.19(e) of this chapter (Rules of Practice and Procedure), relating to offers of settlement, the" and adding in lieu thereof "The";

§ 2.62 [Amended]

(h) In § 2.62(a), by removing "§§ 1.8(d) and 154.27 of this chapter, *i.e.*, Rules of Practice and Procedure and Regulations Under the Natural Gas Act, respectively," and adding in lieu thereof § 385.214 and § 154.27 of this chapter.";

§ 2.68 [Amended]

(i) In the first sentence of § 2.68(b), by removing "§ 1.7 of the Commission's

rules of practice and procedure in" and adding in lieu thereof "§ 385.207 of ";

§ 2.78 [Amended]

(j) In § 2.78(a)(2), by removing "§ 1.7(b) of the Commission's rules of practice and procedure" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 2.78 [Amended]

(k) In the first sentence of § 2.78(b), by removing "§ 1.7(b) of this chapter and shall conform to the requirements of § 1.15 and § 1.16" and adding in lieu thereof "§ 385.1501";

§ 2.100 [Amended]

(l) In the second sentence of § 2.100(c), by removing "§ 1.31(b)(2) of the Commission's General Rules" and adding in lieu thereof "§ 385.711(b)(4) of this chapter";

PART 3—ORGANIZATION; OPERATION; INFORMATION AND REQUESTS

6. Part 3 of Chapter I is amended as follows:

§ 3.8 [Amended]

(a) In the last sentence of § 3.8(e), by removing "§ 1.36(a)" and adding in lieu thereof "§ 388.106 of this chapter";

§ 3.103 [Removed]

(b) In § 3.103, by removing the entire section.

PART 3a—NATIONAL SECURITY INFORMATION

7. Part 3a of Chapter I is amended as follows:

§ 3a.11 [Amended]

(a) In § 3a.11(d)(1), by removing "§ 1.36(c)(14) of the rules of practice and procedures of the Federal Power Commission (18 CFR 1.36(c)(14))." and adding in lieu thereof "§ 388.105(n) of this chapter"

PART 3c—STANDARDS OF CONDUCT

8. Part 3c of Chapter I is amended as follows:

§ 3c.5 [Amended]

(a) In § 3c.5(d)(3), by removing "Section 1.4(c) of the Federal Power Commission's rules of practice and procedure (18 CFR 1.4(c))" and adding in lieu thereof "Section 385.2103 of this chapter,"

§ 3c.6 [Amended]

(b) In the first sentence of § 3c.6(c), by removing "Section 1.36 of the Commission's rules of practice and procedure (18 CFR 1.36)" and adding in lieu thereof "Part 388 of this chapter", and, in the second sentence thereof, by deleting "Section 1.36(f)" and adding in lieu thereof "Section 388.107 of this chapter";

§ 3c.11 [Amended]

(c) In § 3c.11(f)(2), by removing "Section 1.36 of the Federal Power Commission's Rules of Practice and Procedure (18 CFR 1.36)" and adding in lieu thereof "Part 388 of this chapter";

§ 3c.11 [Amended]

(d) In § 3c.11(g)(2), by removing "Section 1.4(c) of the Federal Power Commission's Rules of Practice and Procedure (18 CFR 1.4(c)." and adding in lieu thereof "Section 385.2103 of this chapter";

§ 3c.106 [Amended]

(e) In the first sentence of §3c.106 (f)(2)(iii), by removing "Section 1.4(e) of the Federal Power Commission's Rules of Practice and Procedure (18 CFR 1.4(c))" and adding in lieu thereof "Section 385.2103 of this chapter";

§ 3c.107 [Amended]

(f) In the first sentence of § 3c.107(b)(2), by removing "Section 1.36 of the Commission's Rules of Practice and Procedure (18 CFR 1.36)" and adding in lieu thereof "Section 388.107 of this chapter";

§ 3c.107 [Amended]

(g) In the second sentence of § 3c.107(b)(2), by removing "§ 1.36(f)" and adding in lieu thereof "§ 388.107 of this chapter";

§ 3c.112 [Amended]

(h) In the first sentence of § 3c.112(h)(2), by removing "Section 1.4(c) of the Federal Power Commission's Rules of Practice and Procedure (18 CFR 1.4(c))" and adding in lieu thereof "Section 385.2103 of this chapter";

§ 3c.205 [Amended]

(i) In the first sentence of § 3c.205(b)(2), by removing "Section 1.36 of the Commission's Rules of Practice and Procedure (18 CFR 1.36)" and adding in lieu thereof "Part 388 of this chapter"; and, in the second sentence thereof, by deleting "§ 1.36(f)" and adding in lieu thereof "Section 388.107 of this chapter";

§ 3c.206 [Amended]

(j) In § 3c.206(f)(2), by removing "Section 1.36 of the Federal Power Commission's Rules of Practice and Procedure (18 CFR 1,.36)" and adding in lieu thereof "Part 388 of this chapter".

PART 4—LICENSES, PERMITS, EXEMPTIONS, AND DETERMINATION OF PROJECT COSTS

9. Part 4 of Chapter I is amended as follows:

§ 4.5 [Amended]

(a) In § 4.5, by removing "§ 1.20" and adding in lieu thereof "Subpart E of Part 385";

§ 4.14 [Amended]

(b) In § 4.14(a), by removing "§ 1.20" and adding in lieu thereof "Subpart E of Part 385";

§ 4.23 [Amended]

(c) In the third sentence of §4.23, by removing "§ 1.20" and adding in lieu thereof "Subpart E of Part 385";

§ 4.31 [Amended]

(d) In §4.31(a) by removing "Conform to the requirements of §§ 1.5, 1.14, 1.15, 1.16, and 1.17 of this chapter, except as otherwise described in this part; and" and adding in lieu thereof "[Reserved]";

§ 4.33 [Amended]

(e) In § 4.33(b), by removing "must conform to the requirements of §§ 1.14, 1.15, 1.16, and 1.17 of this chapter, and";

§ 4.81 [Amended]

(d) In § 4.81(c)(3), by removing "§ 1.14(a)(2)" and adding in lieu thereof "§ 385.1901";

§ 4.92 [Amended]

(e) In § 4.92(b) by removing the text of paragraph (b)(1) and adding in lieu thereof "[Reserved]";

§ 4.92 [Amended]

(f) In § 4.92(c)(1)(i), by removing "§ 1.7(b)" and adding in lieu thereof "§ 385.1501";

§ 4.92 [Amended]

(g) In the last sentence of § 4.92(c)(2), by removing "18 CFR 1.7(b)" and adding in lieu thereof "18 CFR 385.1901";

§ 4.103 [Amended]

(h) In § 4.103(d), by removing "§ 1.7" and adding in lieu thereof "§ 385.207";

§ 4.107 [Amended]

(j) in § 4.107(a)(1), by removing the last sentence;

PART 12—SAFETY OF WATER POWER PROJECTS AND PROJECT WORKS

10. Part 12 of Chapter I is amended as follows:

§ 12.2 [Amended]

(a) In § 12.2(b), by removing "§ 1.7" and adding in lieu thereof "§ 385.207";

§ 12.4 [Amended]

(b) In § 12.4(c)(1) by removing "§ 1.7" and adding in lieu thereof "§ 385.207".

PART 16—PROCEDURES RELATING TO TAKEOVER AND RELICENSING OF LICENSED PROJECTS

11. Part 16 of Chapter I is amended as follows:

§ 16.4 [Amended]

(a) In § 16.4, by removing "§§ 1.37 and 2.1" and adding in lieu thereof "§ 2.1 and Subpart M of Part 385";

§ 16.9 [Amended]

(b) In § 16.9, by removing "§ 1.34" and adding in lieu thereof "§ 385.713";

PART 25—APPLICATION FOR VACATION OF WITHDRAWAL AND FOR DETERMINATION PERMITTING RESTORATION OF ENTRY

12. Part 25 of Chapter I is amended as follows:

§ 25.2 [Amended]

(a) In § 25.2, by removing "§ 1.20" and adding in lieu thereof Subpart E of Part 385.".

PART 32—INTERCONNECTION OF FACILITIES; EMERGENCIES, TRANSMISSION TO FOREIGN COUNTRY

13. Part 32 of Chapter I is amended as follows:

§ 32.4 [Amended]

(a) In § 32.4, by removing "and must conform, in all other respects, to the requirements of §§ 1.15 through 1.17 of this chapter";

§ 32.37 [Amended]

(b) In § 32.37, by removing "and must conform, in all other respects, to the requirements of §§ 1.15 through 1.17 of this chapter";

§ 32.61 [Amended]

(c) In the first sentence of § 32.61(i), by removing "and shall conform, in all other respects, to the requirements of §§ 1.15 through 1.17 of this chapter".

PART 33—APPLICATION FOR SALE, LEASE, OR OTHER DISPOSITION, MERGER OR CONSOLIDATION OF FACILITIES OR FOR PURCHASE OR ACQUISITION OF SECURITIES OF A PUBLIC UTILITY

14. Part 33 of Chapter I is amended as follows:

§ 33.5 [Reserved]

(a) In § 33.5, by removing the text of the entire section and adding in lieu thereof "[Reserved]".

PART 35—FILING OF RATE SCHEDULES

15. Part 35 of Chapter I is amended as follows:

§ 35.8 [Amended]

(a) In the first sentence of the fourth paragraph of the notice form in § 35.8(a), by removing "§§ 1.8 and 1.10 of the Commission's rules of practice and procedure (18 CFR 1.8, 1.10)" and adding in lieu thereof "§ 385.212 and § 385.207 of this chapter";

§ 35.13 [Amended]

(a) In the second sentence of § 35.13(a), by removing "§ 1.7" and adding in lieu thereof "§ 385.207";

§ 35.14 [Amended]

(c) In § 35.14(a)(10), by removing "§ 1.7(b) of the rules of practice and procedure" and adding in lieu thereof "§ 385.2010 of this chapter";

PART 41—ACCOUNTS, RECORDS, AND MEMORANDA

16. Part 41 of Chapter I is amended as follows:

§ 41.4 [Amended]

(a) In § 41.4, by removing the first sentence and adding in lieu thereof

"Each copy of such memorandum must be complete in itself.";

§ 41.4 [Amended]

(b) In the second sentence of § 41.4, by removing "§ 1.29" and adding in lieu thereof "§ 385.706(c)";

§ 41.7 [Amended]

(c) In the first sentence of § 41.7, by removing "§ 1.20" and adding in lieu thereof "Subpart E of Part 385";

PART 131—FORMS

17. Part 131 of Chapter I is amended as follows:

§ 131.1 [Reserved]

(a) In § 131.1, by removing the text of the entire section and adding in lieu thereof "[Reserved]".

PART 152—APPLICATION FOR EXEMPTION FROM THE PROVISIONS OF THE NATURAL GAS ACT PURSUANT TO SECTION 1(C) THEREOF

18. Part 152 of Chapter I is amended as follows:

§ 152.2 [Amended]

(a) In the first sentence of § 152.2, by removing "and shall conform, in all other respects with §§ 1.15 and 1.16 of this chapter";

PART 153—APPLICATION FOR AUTHORIZATION TO EXPORT OR IMPORT NATURAL GAS

19. Part 153 of Chapter I is amended as follows:

§ 153.2 [Amended]

(a) In the first sentence of § 153.2, by removing "and shall conform, in all other respects with §§ 1.15 and 1.16 of this chapter";

§ 153.11 [Amended]

(b) In the first sentence of § 153.11, by removing "and shall conform in all other respects with §§ 1.15 and 1.16 of this chapter".

PART 154—RATE SCHEDULES AND TARIFFS

20. Part 154 of Chapter I is amended as follows:

§ 154.94 [Amended]

(a) In the second sentence of § 154.94(j)(5)(ii), by removing "Section 1.28" and adding in lieu thereof "Section 385.715";

§ 154.105 [Amended]

(b) In the first sentence of § 154.105(j), by removing "§ 1.7(b) of the Commission's rules of practice and procedure (18 CFR 1.7(b))" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 154.106 [Amended]

(c) In the first sentence of § 154.106(h), by removing "§ 1.7(b) of the Commission's rules of practice and procedure (§ 1.7(b) of this chapter)" and adding in lieu thereof "§ 385.101 of this chapter";

§ 154.107 [Amended]

(d) In the first sentence of § 154.107(e), by removing "§ 1.7(b) of this chapter of the Commission's rules of practice and procedure" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 154.108 [Amended]

(e) In the first sentence of § 154.108(e), by removing "§ 1.7(b) of this chapter of the Commission's rules of practice and procedure" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 154.109 [Amended]

(f) In the first sentence of § 154.109(f), by removing "§ 1.7(g) of the Commission's rules of practice and procedure (18 CFR 1.7(b))" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 154.109 [Amended]

(g) In the first sentence of § 154.109a(e), by removing "§ 1.7(b) of the Commission's rules of practice and procedure in this chapter (18 CFR

1.7(b))" and adding in lieu thereof "§ 385.1901 of this chapter".

PART 156—APPLICATIONS FOR ORDERS UNDER SECTION 7(a) OF THE NATURAL GAS ACT

21. Part 156 of Chapter I is amended as follows:

§ 156.3 [Amended]

(i) In the second sentence of § 156.3(a), by removing ", and applicable requirements of the Commission's rules of practice and procedure, particularly §§ 1.5, 1.15, 1.16, and 1.17 of this chapter";

§ 156.3 [Amended]

(b) In the second sentence of § 156.3(a), by removing "§ 1.11" and adding in lieu thereof "§ 385.213 and § 385.214";

§ 156.5 [Amended]

(c) In § 156.5(c), by removing the last sentence;

§ 156.7 [Amended]

(d) In § 156.7, by removing the next to last sentence;

§ 156.10 [Amended]

(e) In § 156.10, by removing "§ 1.19(b)" and adding in lieu thereof "§ 385.2009".

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

22. Part 157 of Chapter I is amended as follows:

§ 157.6 [Amended]

(a) In the second sentence of § 157.6(a), by removing ", and other applicable requirements of the Commission's rules of practice and procedure, particularly §§ 1.5, 1.15, 1.16 and 1.17 of this chapter";

§ 157.6 [Amended]

(b) In the third sentence of § 157.6(a), by removing "§ 1.11" and adding in lieu thereof "§ 385.213 and § 385.214";

§ 157.6 [Amended]

(c) In § 157.6(c), by removing "§ 1.32(b)" and adding in lieu thereof "§ 385.802";

§ 157.8 [Amended]

(d) In the third sentence of § 157.8, by removing "§ 1.14" and adding in lieu thereof "§ 385.2001(b)";

§ 157.10 [Amended]

(e) In the first sentence of § 157.10, by removing "§ 1.8" and adding in lieu thereof "§ 385.212";

§ 157.10 [Amended]

(f) In the fourth sentence of § 157.10, by removing "§§ 1.7, 1.8 and 1.37(f)" and adding in lieu thereof "§ 385.212";

§ 157.10 [Amended]

(g) In the last sentence of § 157.10, by removing "§ 1.10" and adding in lieu thereof "§ 385.209";

§ 157.11 [Amended]

(h) In the first sentence of § 157.11(a), by removing "§ 1.19(b)" and adding in lieu thereof "§ 385.2009";

§ 157.11 [Amended]

(i) In § 157.11(b), by removing "§ 1.32(b)" and adding in lieu thereof "§ 385.802";

§ 157.14 [Amended]

(j) In the last sentence of § 157.14(a)(10)(vi), by removing "paragraph (f) of § 1.36" and adding in lieu thereof "§ 388.107";

§ 157.14 [Amended]

(k) In the second sentence of § 157.14(c), by removing "and shall conform in all other respects with §§ 1.15, 1.16, and 1.17 of this chapter unless otherwise directed by the Secretary";

§ 157.26 [Amended]

(l) In § 157.26, by removing the text of the section and adding in lieu thereof "An application under § 157.23 (which shall include the originals of all exhibits accompanying the applications) shall be verified.";

§ 157.101 [Amended]

(m) In § 157.101(c), by removing "§ 1.34" and adding in lieu thereof § 385.713".

PART 158—ACCOUNTS, RECORDS, AND MEMORANDA

23. Part 158 of Chapter I is amended as follows:

§ 158.3 [Amended]

(a) In the first sentence of § 158.3, by removing "§ 1.17" and adding in lieu thereof "§ 385.2010";

§ 158.4 [Amended]

(b) in § 158.4(c), by removing the first sentence and adding in lieu thereof "Each memorandum must be complete in itself."; and in the second sentence, by removing "§ 1.29" and adding in lieu thereof "§ 385.706";

§ 158.7 [Amended]

(c) in § 158.7, by removing "§ 1.20" and adding in lieu thereof "Subpart E of Part 385".

PART 250—FORMS

24. Part 250 of Chapter I is amended as follows:

§ 250.1 [Reserved]

(a) In § 250.1, by removing the text of the section and adding in lieu thereof "[Reserved]".

PART 270—RULES GENERALLY APPLICABLE TO REGULATED SALES OF NATURAL GAS

25. Part 270 of Chapter I is amended as follows:

§ 270.202 [Amended]

(a) In § 270.202(d), by removing "§ 1.41" and adding in lieu thereof "Subpart K of Part 385".

PART 271—CEILING PRICES

26. Part 271 of Chapter I is amended as follows:

§ 271.402 [Amended]

(a) In the first sentence of § 271.402(c)(5), by removing § 1.7(b)" and adding in lieu thereof "§ 385.1901";

§ 271.806 [Amended]

(b) In the last sentence of § 271.806(c), by removing "§ 1.7(c) of the Commission's Rules of Practice and Procedure (18 CFR 1.7(c))" and adding in lieu thereof "§ 385.207 of this chapter";

§ 271.1106 [Amended]

(c) In § 271.1106, by removing "§ 1.41" and adding in lieu thereof "Subpart K of Part 385".

PART 275—COMMISSION DETERMINATIONS AND REVIEW OF JURISDICTIONAL AGENCY DETERMINATIONS

27. Part 275 of chapter I is amended as follows:

§ 275.204 [Amended]

(a) In § 275.204(f), by removing "§§ 1.17 and 1.51" and adding in lieu thereof "§ 385.2010".

PART 281—NATURAL GAS CURTAILMENT UNDER THE NATURAL GAS POLICY ACT OF 1978

28. Part 281 of Chapter I is amended as follows:

§ 281.110 [Amended]

(a) In § 281.110(b), by removing "§ 1.6" and adding in lieu thereof "§ 385.206";

§ 281.111 [Amended]

(b) In the first sentence of § 281.111, by removing "§ 1.7 of the Commission's regulations" and adding in lieu thereof "§ 385.207 of this chapter";

§ 281.214 [Amended]

(c) In § 281.214(a), by removing "§ 1.6" and adding in lieu thereof "§ 285.206";

§ 281.215 [Amended]

(d) In the first sentence of § 281.215, by removing "§ 1.7 of the Commission's Regulations" and adding in lieu thereof "§ 385.207 of this chapter".

PART 282—INCREMENTAL PRICING

§ 282.20 [Amended]

29. Part 282 of Chapter I is amended as follows:

§ 282.201 [Amended]

(a) In the last sentence of § 282.201, by removing "§ 1.41" and adding in lieu thereof "Subpart K of Part 385 of this chapter";

§ 282.204 [Amended]

(b) In § 282.204(f)(2), by removing "§ 1.10" and adding in lieu thereof "§ 385.209 of this chapter";

§ 282.206 [Amended]

(c) In § 282.206(a)(2)(i), by removing "§ 1.7" and adding in lieu thereof "§ 385.207 of this chapter";

§ 282.206 [Amended]

(d) In the first sentence of § 282.206(b)(2)(i), by removing "§ 1.41(h)" and adding in lieu thereof "§ 385.1108(h) of this chapter";

§ 282.403 [Amended]

(e) In § 282.403(g)(1), by removing "§ 1.10" and adding in lieu thereof "§ 385.209 of this chapter".

PART 284—CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

30. Part 284 of chapter I is amended as follows:

§ 284.6 [Amended]

(a) In § 284.6(a), by removing "§ 1.42" and adding in lieu thereof "subpart L of Part 385";

§ 284.208 [Amended]

(b) In § 284.208(d)(1), by removing "§ 1.32" and adding in lieu thereof "Subpart H of Part 385";

§ 284.222 [Amended]

(c) In the first sentence of § 284.222(b), by removing "§§ 1.32 and 157.11" and adding in lieu thereof "§ 157.11 and subpart H of Part 385 of this chapter".

PART 286—ADMINISTRATIVE PROCEDURES

31. Part 286 of chapter I is amended as follows:

§ 286.102 [Amended]

(a) In § 286.102(c), by removing "Part 1, Subchapter H, Chapter I" and adding in lieu thereof "§ 385.713 of this chapter".

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

32. Part 292 of Chapter I is amended as follows:

§ 292.207 [Amended]

(a) In the first sentence of the third paragraph of the notice form in § 292.207(b)(6)(ii), by removing "§§ 1.8 and 1.10 of the Commission's rules of

practice and procedure" and adding in lieu thereof "§ 385.214 and § 385.209 of this chapter".

PART 375—THE COMMISSION

33. Part 375 of Chapter I is amended as follows:

§ 375.202 [Amended]

(a) In § 375.202(b)(1), by removing "§ 1.1(f)(19)" and adding in lieu thereof "§ 388.101(c)";

§ 375.202 [Amended]

(b) In § 375.202(b)(2), by removing "§ 1.36(c)(2)" and adding in lieu thereof "§ 388.105(b)";

(c) In the last sentence of § 375.301, by removing "§ 1.7(d)" and adding in lieu thereof "§ 385.1902";

(d) By adding to § 375.301 a new paragraph to read as follows:

§ 375.301 Purpose.

* * * * *

(c) For purposes of Subpart C, "uncontested" and "in contested cases" mean that no motion to intervene, or notice of intervention, in opposition to the pending matter made under § 385.214 (intervention) has been received by the Commission.

§ 375.302 [Amended]

(e) In the first sentence of § 375.302(b) by removing "§ 1.8" and adding in lieu thereof "§ 385.212";

(f) In § 375.302, by removing paragraph (f);

(g) In § 375.302(g), by removing after "extension of time" the following: "(other than motions made while a proceeding is pending before a presiding officer as defined in § 385.102(d))", and by deleting "Part 1" and adding in lieu thereof "Part 385";

§ 375.304 [Amended]

(h) In § 375.304, by removing "the Commission's rules of practice and procedure, particularly § 1.27" and adding in lieu thereof "Part 385, particularly § 385.504";

§ 375.307 [Amended]

(i) In § 375.307(g), by removing "§ 1.11(d)(1) of this Chapter" and adding in lieu thereof "§ 385.214 of this chapter";

§ 375.307 [Amended]

(j) In § 375.307(j), by removing "§ 1.14(a)(2) of this Chapter" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 375.308 [Amended]

(k) In § 375.308(h), by removing "§ 1.11(d)(3)" and adding in lieu thereof "§ 385.214";

§ 375.308 [Amended]

(l) In § 375.308(o), by removing "§ 1.14(a)(2)" and adding in lieu thereof "§ 385.1901";

§ 375.308 [Amended]

(m) In § 375.308(gg), by removing "§ 1.14(a)(2) of this Chapter" and adding in lieu thereof "§ 385.1901 of this chapter";

§ 375.309 [Amended]

(n) In § 375.309(b), by removing "§ 1.12 of this Chapter" and adding in lieu thereof "§ 1b.12 of this chapter"; and

§ 375.310 [Amended]

(o) In § 375.310(a), by removing "§ 1.38 and § 1.40" and adding in lieu thereof "Subpart I and Subpart J of Part 385 of this chapter".

34. Chapter I, Title 18 of the *Code of Federal Regulations* is amended by adding the following:

Form of Notice for "Federal Register"

Oil pipeline carriers must file a form of notice suitable for publication in the **Federal Register** in the following form:

United States of America Federal Energy Regulatory Commission

(Name of Carrier) ———————

Docket No. ———————

Notice of Proposed Changes in FERC Tariff

Take notice that (name of carrier), on (date), tendered for filing proposed changes

in its FERC No. (number); Supp. No. (number) to FERC No. (number); revised page to FERC No. (number) to be effective (or issued) on (date). [The following language in the first paragraph applies only to increased rate filings.] The proposed changes would increase revenues by (dollar amount) based on the 12 month period ending (date). [If changes other than increased rates and charges are proposed, the carrier must state concisely the nature of these changes.]

[The carrier must briefly describe the reasons for the proposed changes in the second paragraph.]

Copies of the filing were served upon the carrier's subscribers.

A person desiring to be heard or to protest said filing should file an intervention or protest with the Office of the Secretary, Federal Energy Regulatory Commission, 825 N. Capitol Street NE., Washington, D.C. 20426, in accordance with Rules 214 and 211 of the Commission's Rules of Practice and Procedure (18 CFR 385.214 and 385.211). The interventions or protests should be filed on or before (date). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. A person wishing to become a party must intervene. Copies of this filing are on file with the Commission and are available for public inspection.

¶ 32,120 High-Cost Gas Produced From Tight Formations, Fruitland Formation (New Mexico-4)

46 F. R. 20218 (April 3, 1981).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-4]

High-Cost Gas Produced from Tight Formations, Fruitland Formation, N. Mex.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of New Mexico Oil Conservation Division that a portion of the Fruitland Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on April 27, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on April 13, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

Issued: March 27, 1981.

I. Background

On March 23, 1981, the State of New Mexico Oil Conservation Division (New Mexico) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that a portion of the Fruitland Formation located in San Juan and Rio Arriba Counties, New Mexico, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New Mexico's recommendation that a portion of the Fruitland Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with New Mexico's recommendation.

New Mexico's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The formation is located in San Juan and Rio Arriba Counties, New Mexico, approximately 18 miles east of the city of Aztec, New Mexico. The recommended area is the Northeast Blanco Unit, which comprises 33,500 acres on the northeast flank of the San Juan Basin. The Fruitland Formation is of upper Cretaceous Age and consists primarily of coal and shale with some tight sandstone stringers. Within the Northeast Blanco Unit, the formation averages 300 feet in thickness and is found at an average depth of 2800 feet.

III. Discussion of Recommendation

New Mexico claims in its submission that evidence gathered through information and testimony presented at a public hearing in New Mexico Case No. 7087 convened by New Mexico on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

New Mexico further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by New Mexico that the Fruitland Formation, as described and delineated in New Mexico's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before April 27, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (New Mexico–4), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 confirmed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than April 13, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event New Mexico's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (45) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(2) through (44) [Reserved]

(45) *Fruitland Formation in New Mexico.* RM79–76 (New Mexico–4)

(i) *Delineation of formation.* The Fruitland Formation consists of the Northeast Blanco Unit, found in San Juan and Rio Arriba Counties, New Mexico, approximately 18 miles east of the city of Aztec, New Mexico, on the Northeast flank of the San Juan Basin.

(ii) *Depth.* The Fruitland Formation is overlain by the Kirtland Shale and Farmington Sandstone and underlain by the Pictured Cliffs Formation. The average depth to the top of the Fruitland Formation underlying the Northeast Blanco Unit is 2800 feet.

¶ 32,121 High-Cost Gas Produced From Tight Formations, Abo Formation (New Mexico-3)

46 F. R. 20219 (April 3, 1981).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-3]

High-Cost Gas Produced from Tight Formations Abo Formation, N. Mex.

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of New Mexico Oil Conservation Division that the Abo Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on April 27, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on April 13, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

SUPPLEMENTARY INFORMATION:

Issued: March 27, 1981.

I. Background

On March 23, 1981, the State of New Mexico Oil Conservation Division (New Mexico) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that portions of the Abo Formation located in Chaves and DeBaca Counties, New Mexico, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New Mexico's recommendation that the Abo Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with New Mexico's recommendation. New Mexico's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located in DeBaca County, New Mexico in Township 2 South, Ranges 22 thru 27 East and Township 3 South, Ranges 22 thru 26 East and in Chaves County, New Mexico in Township 3 South, Range 27 East, Townships 4, 5, 9 and 10 South, Ranges 22 thru 27 East, Townships 6 thru 8 South, Ranges 22 thru 28 East, Township 11 South, Ranges 22 thru 25 East, Township 12 South, Ranges 22 thru 24 East, Township 13 South, Ranges 22 and 23 East, Township 9½ South, Range 24 East and Township 14 South, Range 22 East. The proposed area underlies approximately 1,536,000 acres and encompasses Roswell, New Mexico,

which is located in the southern part of the area. The Abo Formation consists of very fine-grained sandstone ranging from 535 to 818 feet in thickness, averaging about 677 feet. The average depth to the top of the formation is 3650 feet.

III. Discussion of recommendation

New Mexico claims in its submission that evidence gathered through information and testimony presented at a public hearing in New Mexico Case No. 7093 convened by New Mexico on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed areas is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

New Mexico further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by New Mexico that the Abo Formation, as described and delineated in New Mexico's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views, or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D. C. 20426, on or before April 27, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (New Mexico-3), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D. C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than April 13, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event New Mexico's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (44) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in

the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(22) through (43) [Reserved]

(44) *Abo Formation in New Mexico.* RM79–76 (New Mexico-3)

(i) *Delineation of formation.* The Abo Formation is located in DeBaca County, New Mexico, Township 2 South, Ranges 22 thru 27 East and Township 3 South, Ranges 22 thru 26 East and in Chaves County, New Mexico, Township 3 South, Range 27 East, Townships 4, 5, 9 and 10 South, Ranges 22 thru 27 East, Townships 6 thru 8 South, Ranges 22 thru 28 East, Township 11 South, Ranges 22 thru 25 East, Township 12 South, Ranges 22 thru 24 East, Township 13 South, Ranges 22 and 23 East, Township 9½ South, Range 24 East and Township 14 South, Range 22 East.

(ii) *Depth.* The Abo Formation averages about 677 feet in thickness and the depth to the top of the formation averages 3650 feet.

* * * * *

¶ 32,122 High-Cost Gas Produced From Tight Formations (Mississippi-1)

46 F. R. 20683 (April 7, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Mississippi—1)]

High-Cost Gas Produced From Tight Formations

Issued: April 1, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the State Oil and Gas Board of Mississippi that the Upper Hosston Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on May 1, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on April 16, 1981

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Leslie Lawner, (202) 357-8307 or John Bassett/Ting Chin, (202) 357-8589/8595.

SUPPLEMENTARY INFORMATION: .

I. Background

On March 5, 1981, the State Oil and Gas Board of Mississippi (Mississippi) submitted to the Commission a recommedation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Upper Hosston Formation in Jefferson Davis County, Mississippi, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Mississippi's recommendation that the Upper Hosston Formation be designated a tight formation should be adopted. Mississippi's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of the Recommendation

Mississippi recommends that the Upper Hosston Formation found in the south half of Township 9 North, Range 19 West, Jefferson Davis County, Mississippi, be designated as a tight formation.

The top of the recommended formation varies from 14,000 to 14,700 feet, with the bottom of the formation at approximately 15,900 feet. The only producing well in the Upper Hosston Formation in the recommended area is completed in an interval of 14,460 feet to 14,570 feet. The Upper Hosston Formation lies immediately below the James Formation.

III. Discussion of Recommendation

Mississippi claims in its submission that evidence gathered and presented at a public hearing in support of this recommedation demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommeded formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Mississippi further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Mississippi that the Upper Hosston Formation, as described and delineated in Mississippi's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before May 1, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Mississippi-1), and should give reasons including supporting data for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission.

Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than April 16, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Mississippi's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(40) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(40) *Upper Hosston Formation in Mississippi.* RM79–76 (Mississippi–1).

(i) *Delineation of Formation.* The Upper Hosston Formation is found in the south half of Township 9 North, Range 19 West, Jefferson Davis County, Mississppi

(ii) *Depth.* The top of the Upper Hosston Formation varies from 14,000 feet to 14,700 feet and the base of the formation is at approximately 15,900 feet.

* * * * *

¶ 32,123 High-Cost Gas Produced From Tight Formations (Texas-8)

46 F. R. 20684 (April 7, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—8)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

Issued: April 1, 1981.

AGENCY: [Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Railroad Commission of Texas that the Geopressured Wilcox Lobo Sandstone Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on May 1, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on April 16, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–0307 or John Bassett/Ting Chin, (202) 357–8589/8595.

SUPPLEMENTARY INFORMATION:

I. Background

On March 2, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Geopressured Wilcox Lobo Sandstone Formation, located in the southern part of the State of Texas, in Webb and Zapata Counties, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Geopressured Wilcox Lobo Sandstone Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Geopressured Wilcox Lobo Sandstone Formation (hereinafter referred to as the "Geopressured Wilcox Lobo"), located in Webb and Zapata Counties of Texas Railroad Commission District 4, be designated as a tight formation. Within the aforementioned two-county area, a portion of the formation is not included in the recommendation. The portion not being recommended at this notice time is a part of southwest Webb County and a part of northwest Zapata County. (See Appendix B contained in the recommendation on file with the Commission). The Geopressured Wilcox Lobo is located below the Lower Wilcox Group and above the Wills Point Formation which is a part of the Midway Group. The principal correlative members of the formation are the Upper Lobo, Lobo 1, Lobo 3 and Lobo 6 with the Lobo 1 and Lobo 6 members being the major gas producing reservoirs. The Texas recommendation includes only those reservoirs that are

geopressured (pressure greater than 0.465 psi per foot of true vertical depth). The approximate thickness of the Geopressured Wilcox Lobo varies from 1,175 feet in the north to 3,130 feet in the south. The highest portion of the recommended formation appears at 5,840 feet.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980, in Docket No. RM80-68 (45 F.R. 53458, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Geopressured Wilcox Lobo Sandstone Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking submitting written data, views or arguments to the Federal Energy Regulatory Commission Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before May 1, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas-8), and should give reasons, including supporting data, for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than April 16, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(41) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's file in Docket No. RM79–76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

• • • • •

(41) *Geopressured Wilcox Lobo Sandstone Formation in Texas.* RM79–76 (Texas–8)

(i) *Delineation of formation.* The Geopressured Wilcox Lobo Sandstone Formation is found in the southern part of Texas in Webb and Zapata Counties, Railroad District 4, and is located below the Lower Wilcox Group and above the Wills Point Formation which is part of the Midway Group.

(ii) *Depth.* The highest portion of the Geopressured Wilcox Lobo Sandstone Formation appears at 5,840 feet. The approximate thickness varies from 1,175 feet in the north to 3,130 feet in the south.

• • • • •

¶ 32,124 High-Cost Gas Produced From Tight Formations (Texas-9)

46 F. R. 20685 (April 7, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—9)]

Issued: April 1, 1981.

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that the Travis Peak Formation in the Sym-Jac, West (Hosston) Field be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on May 1, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on April 16, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner; (202) 357–8307, or Ting Chin, (202) 357–8595/John Bassett (202) 357–8589.

SUPPLEMENTARY INFORMATION:

I. Background

On March 16, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Travis Peak Formation in the Sym-Jac, West (Hosston) Field, located in the eastern part of the State of Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Travis Peak Formation in the Sym-Jac, West (Hosston) Field be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Travis Peak Formation in the Sym-Jac, West (Hosston) Field, encountered in Cherokee County, Texas, Railroad Commission District 6, be designated as a tight formation. The particular area being recommended is located about 5 miles south of the city of Rusk, county seat of Cherokee County, Texas. The Travis Peak Formation is the basal formation of the Lower Cretaceous series and overlies the Jurassic Cotton Valley Sands and is below the Pettit Formation.

The total formation thickness is approximately 2,200 feet in the only well in the field which penetrated the entire Travis Peak Formation. The approximate top and base of the formation in the recommended area are 9,850 feet and 12,050 feet, respectively. Most of the gas production is from the upper 500 feet of the formation.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Travis Peak Formation in the Sym-Jac West (Hosston) Field, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before May 1, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas-9), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commisssion's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than April 16, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(42) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(42) *Travis Peak Formation in the Sym-Jac, West (Hosston) Field in Texas.* RM79-76 (Texas-9)

(i) *Delineation of formation.* The Travis Peak Formation in the Sym-Jac, West (Hosston) Field is found in Cherokee County, Texas, Railroad Commission District 6.

(ii) *Depth.* The top and base of the Travis Peak Formation are found at approximately 9,850 feet and 12,050 feet, respectively, giving a thickness of aproximately 2,200 feet.

* * * * *

¶ 32,125 High-Cost Gas Produced From Tight Formations (Louisiana-4)

46 F. R. 20686 (April 7, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Louisiana—4)]

High-Cost Gas Produced From Tight Formations

Issued: April 1, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the State of Louisiana Office of Conservation that the Gray Sand, Reservoir A, be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on May 1, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on April 16, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Ting Chin, (202) 357-8595/John Bassett (202) 357-8589.

SUPPLEMENTARY INFORMATION:

I. Background

On March 12, 1981, the State of Louisiana Office of Conservation (Louisiana) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Gray Sand, Reservoir A, located in the central portion of north Louisiana, be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Louisiana's recommendation that the Gray Sand Reservoir A, be designated a tight formation should be adopted. Louisiana's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The Gray Sand, Reservoir A, underlying specified portions of the Terryville and Sugar Creek Fields in Claiborne and Lincoln Parishes, north Louisiana, consists of interbedded sandstone, limestone, and shale. The recommended area is described below. It is defined as that sand occurring between the measured depths of 12,840 feet and 13,350 feet on the induction electrical log of the IMC Exploration Company—Eugene Tinsley *et al.* No. 1 Well.

Recommended area

T18N-R4W	Sections 3, 4, 5, 8.
T18N-R5W	Section 1.
T19N-R4W	Sections 3-10, 15-23, 26-34.
T19N-R5W	All Sections.
T19N-R6W	Sections 1, 12, 13, 24, 25, 36.

III. Discussion of the Recommendation

Louisiana claims in its submission that evidence gathered through

information and testimony presented at a public hearing convened by Louisiana on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Louisiana further asserts that the requirements of Statewide Order No. 29-B will assure that development of the Gray Sand, Reservoir A, will not adversely affect any fresh water aquifer that is or is expected to be used as a domestic or agricultural water supply. In addition, Louisiana states that it is in the process of establishing rules and regulations in accordance with the Environmental Protection Agency's Underground Injection Control guidelines which it believes will further prevent the contamination of any fresh water aquifer.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued August 1, 1980 in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Louisiana that the Gray Sand, Reservoir A, as described and delineated in Louisiana's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before May 1, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Louisiana—4), and should give reasons, including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing.

Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than April 16, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Louisiana's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(43) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in

the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(43) *Gray Sand, Reservoir A, in Louisiana.* RM79-76 (Louisiana—4).

(i) *Delineation of formation.* The Gray Sand, Reservoir A, consisting of interbedded sandstone, limestone and shale, is found in the following portions of Lincoln and Claiborne Parishes, north Louisiana: T18N-R4W, Sections 3, 4, 5, 6; T18N-R5W, Section 1; T19N-R4W, Sections 3-10, 15-23, 26-34; T19N-R5W, all sections; T19N-R6W, Sections 1, 12, 13, 24, 25, 36.

(ii) *Depth.* The Gray Sand, Reservoir A, is defined as that sand occurring between the measured depths of 12,840 feet and 13,350 feet on the induction electrical log of the IMC Exploration Company—Eugene Tinsley *et al.* No. 1 Well located in Section 33, Township 19 North, Range 4 West, Lincoln Parish.

* * * * *

¶ 32,126 Annual Report of Gas Supply for Certain Natural Gas Pipelines: Form No. 15

46 F. R. 21189 (April 9, 1981).

18 CFR Parts 157 and 260

Revised Notice of Proposed Rulemaking Pertaining to the Annual Report of Gas Supply for Certain Natural Gas Pipelines: Form No. 15

Issued April 2, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Revised notice of proposed rulemaking.

SUMMARY: By this Notice, the Federal Energy Regulatory Commission (Commission) seeks further comment on proposed revisions to Commission Form No. 15, Interstate Pipelines' Annual Report of Gas Supply. The proposed amendments would include reducing the reporting requirements in the form, clarifying the accompanying instructions and definitions, and changing the format of the statements and schedules in the form.

As a result of these changes, the Form No. 15 reporting requirements should be reduced by more than fifty percent.

The proposed changes are made as part of the Commission's ongoing program to eliminate unnecessary reporting requirements and to update its forms.

DATE: Comments are due May 4, 1981.

ADDRESS: Comments to this Revised Notice of Proposed Rulemaking should be addressed to the Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80-69.

FOR FURTHER INFORMATION CONTACT:

Wayne Thompason, Chief, Gas Supply Branch, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 4402-B, Washington, D.C 20426, (202) 357-9077.

In the matter of an annual report of gas supply for certain natural gas pipelines: Form No. 15, Docket No. RM80-69, revised notice of proposed rulemaking.

I. Background

A. Description of Form No. 15[*]

Form No. 15, Annual Report of Gas Supply for Certain Natural Gas Pipelines, is designed to obtain a yearly report of the total gas supply of each pipeline company under the jurisdiction of the Federal Energy Regulatory Commission (Commission).[1] The gas supply includes the pipeline company's owned reserves, producer contracts for which a producer has received a certificate to sell the gas to the pipeline,[2] gas purchase contracts with other jurisdictional pipelines,[3] purchases of gas from foreign suppliers, purchases of Liquefied Natural Gas (LNG), Synthetic Natural Gas (SNG), coal gas, and short-term or other purchases over which the Commission has regulatory authority.

The date collected in Form No. 15 are used in considering gas supply issues in certificate applications and curtailment cases, to perform depreciation analyses in rate cases, and to make determinations about new or increased sales of natural gas, the extension of facilities, or the abandonment of service.

[*]Form No. 15 (Attachment A) is not being printed by the Federal Register. Copies of Form No. 15, including all instructions to the form are available in the Commission's Office of Public Information.

[1]Form No. 15 was initially promulgated in 1964: Order No. 279, 29 FR 4874 (April 7, 1964). It has undergone four revisions since that date: Order No. 337, 32 FR 3292 (February 25, 1967); Order No. 339, 35 FR 6962 (May 1, 1970); Order No. 476, 38 FR 6810 (March 13, 1973); and order No. 546, 41 FR 9868 (March 8, 1976).

[2]Pursuant to the Natural Gas Policy Act (15 U.S.C. 3301-3432), in certain instances, producers are no longer required to obtain certificates. (*See* section 601 of the NGPA.)

[3]Pursuant to the NGPA, pipelines are also permitted to purchase gas from intrastate pipeline companies.

B. History of Rulemaking to Amend Form No. 15 (Docket No. RM80-69)

1. *The August, 1980 Notice of Proposed Rulemaking.* On August 7, 1980, the Commission issued a Notice of Proposed Rulemaking to revise Form No. 15 (45 FR 54082, August 14, 1980), as part of its ongoing program to review the data collection forms which are used for Commission decisionmaking purposes in the regulatory process and to reduce the reporting burdens imposed by these forms.

The Notice proposed to amend the content, format and instructions of Form No. 15 in order to make it more concise, better facilitate its use, and reduce unnecessary respondent reporting burdens. The schedules were to be redesigned to better facilitate its use and to improve readability, and the definitions and data requirements were to be standardized and made to conform with changes resulting from passage of the Natural Gas Policy Act of 1978 (NGPA). Under this proposal, companies which filed a magnetic tape (computer readable copy) of the form could continue to submit the magnetic tape in its current format; however, a "hard copy" (computer printout) would have to be filed in the proposed format. These proposed changes to Form No. 15 were to be implemented in time to apply to reports due on April 1, 1981, which would contain 1980 report year data.

2. *Adverse Comments on the August, 1980, Proposed Rule.* Most commenters who responded to the August 7, 1980 Notice of Proposed Rulemaking expressed approval of the Commission's intention to reduce reporting burdens through deletion of certain data items in Form No. 15. However, the majority of commenters strongly objected to the proposed revisions to Form No. 15 on the grounds that the proposed changes would actually create an increase in reporting burdens, at least for the first reporting period after the revisions were to be effected.

Specific complaints cited the excessive and duplicative burden that would be caused by the proposed requirement for respondents to file a magnetic tape of the form in its current format, and also a "hard copy" of the form *in the proposed new format;* they also stressed that there would be a lack of time in which to implement these revisions prior to the April 1, 1981 deadline.

Several commenters suggested that the Form No. 15 should be retained in its current format and unnecessary elements should simply be deleted from its current format.

Many commenters also urged that, in any case, changes should only be effective for reports due on or after April 1, 1982. Other comments stated that certain of the "clarifying" changes and revisions made to conform with recent legislation actually created a greater reporting burden, which conflicted with the Commission's express purpose of reducing reporting burdens. Several of the proposed definitions were allegedly unclear, and conflicted with each other and with the actual data requirements in the form.

Many commenters opposed the Commission's detailed reservoir reporting requirements and favored only field level reporting instead. They also objected to the requirement for the attachment of field maps to the form as expensive and burdensome. Several suggestions were also made for specific changes to definitions, data elements on specific schedules, further deletions, clarifications and reformatting.

One commenter objected because the proposal would have deleted the 20-year annual projection of total pipeline system gas supply requirements and replaced it with a one-year requirements report. The commenter also opposed the elimination of curtailments data for the current report year. The commenter suggested several additional reporting requirements for the form.

Finally, the majority of commenters recommended that the Commission convene a conference between Commission staff and interested persons to discuss the various problems regarding the proposed changes as well

as suggestions for improvements to the form.

These comments were discussed in the Commission's Interim Rule in this docket, issued in November, 1980.

3. *The November, 1980 Interim Rule.* After due consideration of each of the comments to the Notice of Proposed Rulemaking, the Commission issued an Interim Rule on November 6, 1980 (45 FR 75192, November 14, 1980). The Interim Rule provided, among other things, that Form No. 15 was revised by the deletion of those items which were proposed for deletion in the Notice of Proposed Rulemaking; no other changes were made at that time. Thus, the present version of Form No. 15 requires the reporting of 1980 data in accordance with the current format for the Form, minus those items specified for deletion in the November, 1980, Interim Rule; and this Form is due on April 1, 1981.

The Interim Rule also provided that a series of informal public meetings would be held in the near future to discuss further changes to the form.

4. *Informal meetings and additional written comments.* The Commission held informal conferences between members of the public and the Commission staff on December 2, 9, and 16, 1980.[4] At those meetings the basic issues raised in written comments to the Notice of Proposed Rulemaking were discussed in detail, and numerous useful suggestions were offered for less burdensome changes in the Form No. 15 format, definitions, instructions and reporting requirements.[5]

II. Summary of Proposed Revisions to Form No. 15

Upon due consideration of the discussions in each of the informal meetings and all written comments in this docket, the Commission now proposes to make, in addition to those deletions already made by the Interim Rule, the following revisions to that version of Form No. 15 which was proposed for consideration in the Notice of Proposed Rulemaking. Unless otherwise noted, all changes proposed are made in response to the written and oral comments and suggestions offered in this docket.

A. General

Detailed reservoir data which was proposed to be reported in the Notice [6] Schedule II, "Reservoir Data, Field Data, Salable Reserve Data and Deliverability Estimate" would be totally deleted from Form No. 15. Instead, the Commission would combine Notice Schedule II and the Notice Schedule III, "Committed Reserves and Deliverability Estimates for Other Supply Sources." This new Schedule II would be entitled, "Committed Reserves and Deliverability Estimates for All Supply Sources."

The following changes would be made to each of the Notice schedules:

All requirements to state whether the report is an original or a resubmission would be deleted; the "Date of Resubmission" element would be changed to "Date of Submission;" only a "Yes" choice would appear in the "Footnote Made For This Page" item; pagination would be simplified; and a

[4] *See* Notice of Public Meetings, issued November 17, 1980 (45 FR 77043, November 21, 1980), which provided a general outline of topics for discussion in each meeting; Notice of Agenda Change in Public Meetings, issued December 3, 1980 (45 FR 81062, December 9, 1980), which provided for separate meetings to discuss reservoir level reporting, (December 9), field level reporting (December 16), and data automation (January 16, 1981); and Notice of Cancellation of Public Meeting, and Reopening of Comment Period, issued December 24, 1980 (45 FR 1744, January 7, 1981), which provided for the cancellation of the January 16, 1981 meeting on data automation since the meeting was no longer necessary, and for the reopening of the comment period until January 16, 1981.

[5] Copies of the transcripts of the public meetings are available in the Commission's Office of Public Information.

[6] All references to "Notice" schedule, line, item, etc. apply to the proposed schedule, line, item, etc. in the Form No. 15 proposed for revision in the August 7, 1980 Notice of Proposed Rulemaking.

provision included for "Supplemental Sheet No."

B. Identification Schedule and Statements

1. *Notice "Identification Schedule."* The Notice "Identification Schedule" would be revised as follows: The schedule would be renumbered as Page 0001; parenthetical references to "sheets and supplemental pages" would be deleted from the Notice Item 11, as would the reference to "Sheets" in Column 03, "Total Number of Pages/ Sheets", of Notice Item 11; conforming changes would be made to the title of Schedule II; and the Title of the Notice Schedule III would be deleted in its entirety.

2. *Notice "Synopsis of Gas Supply."* The Notice statement, "Synopsis of Gas Supply," would be renumbered as Page 0002 and the following changes would also be made:

Lines 01 and 02 would remain the same.
The Line 03 requirement would be transferred to Page 0004, "Gas Procurement Activity Statement."
New line 03 would report data required in Notice line 06, and include certain clarifying language.
Line 04 would be deleted in its entirety.
New line 04 would report data required in Notice line 08, except that "new reserves certificated" would be changed to "new reserve additions acquired through new gas purchase contracts with independent producers" to conform with requirements in the NGPA.
Line 05 would remain the same.
Line 06 would become new line 03.
Line 07 would be deleted in its entirety.
Line 08 would become new line 04.
Line 09 would be deleted in its entirety.
Line 10 would become new line 06 and include certain clarifying language.
Line 11 would become new line 07 and include certain clarifying language.

3. *Notice "Disclosure of Other Gas Supply Filings With Other Federal Agencies."* The Notice statement, "Disclosure of Other Gas Supply Filings With Other Federal Agencies" would be renumbered as Page 0003, but would otherwise remain the same.

4. *Notice "Gas Procurement Activity Statement."* The Notice "Gas Procurement Activity Statement" would be renumbered as Page 0004. A detailed list that includes company activities which could result in additions to gas supplies would be added to the instructions for clarification.

C. Schedules

The schedule pages and "Footnote Data Page" would be unnumbered so that the appropriate page and supplemental page number could be inserted by the individual reporting companies.

1. *Notice Schedule I, "System Deliverability Summary."* The following change would be made to Notice Schedule I, "System Deliverability Summary":

Current Gas Supply

Lines 101 and 102

Column 02 would be changed from "Producer Dedicated" to "Producer Contracted", for clarification, and to conform with the NGPA.
Column 03 would be changed from "Warranty Contracts" to "Other Supply Contracts" to report supply sources other than owned, producer contracted, and interstate pipeline purchases (this "other supply contracts" data was previously reported in Item 04). Warranty contract data would now be reported in Column 02.
Column 04 would be changed from "Pipeline Purchases" to "Interstate Pipeline Purchases" for clarification.

Deliverability Forecast

Lines 103 through 123

Column 01 would be changed from "Owned and Producer Dedicated" to "Owned and Producer Contracted" for clarification.
A new Column 02 would be added, entitled, "Other Supply Contracts," to conform to the "Other Supply Contracts" reported in the Current Gas Supply portion of Schedule I.

Lines 103 through 123

Column 02 would be renumbered Column 03 and would be changed from "Pipeline Purchases" to "Interstate Pipeline Purchases", to conform with "Interstate

Pipeline Purchases" reported in Current Gas Supply.
Columns 03 and 04 would be renumbered 04 and 05, respectively.
A new Column 06 would be added, entitled, "Total Certificate Requirements" to report, for clarification the maximum delivery obligation under certificates.

A requirement would be added in the instructions to include a footnote explaining if any assumption is made for new Columns 02 and 03 under Deliverability Forecast, other than "receiving full contract quantity."

2. *Notice Schedule II, "Reservoir Data, Salable Reserve Data and Deliverability Estimate," and Notice Schedule III, "Committed Reserves and Deliverability Estimates for Other Supply Sources."* The Notice Schedule II, "Reservoir Data, Salable Reserve Data and Deliverability Estimate," and the Notice Schedule III, "Committed Reserves and Deliverability Estimates for Other Supply Sources," would be revised to delete certain data elements which need not be reported annually because this information is submitted with certificate applications. The new Schedule II would combine the remaining elements in Notice Schedules II and III, and would be entitled, "Committed Reserves and Deliverability Estimates for All Supply Sources". The format would be changed for ease of reporting.

Following are the changes to Notice Schedules II and III which would result from the combination of those schedules into a new Schedule II:

a. *Notice Schedule II, "Reservoir Data, Salable Reserve Data and Deliverability Estimate".* The deletions to Notice Schedule II would be as follows:

Item No.
03—Reservoir Name
04—Geologic Code
08—Year First Reported
09—Type Gas
10—Reservoir Gas Gravity
12—GOR or GLR
13—Reservoir Depth
14—Reservoir Temp. °R
15—Initital Pressure
16—Current Pressure
17—Terminal Pressure
18—Type Pressure
20—Name of Other Interstate Pipeline Purchaser
21—Name of Other Interstate Pipeline Purchaser
33—New Reservoirs
34—Extensions
36—Maximum Daily Quantity
37—Gathering Line Pressure, psia

The following items would be added for clarification purposes:

Item 216, "Additions During Reporting Year";
Item 219, "Total Number of Reservoirs";
Item 220, "Number of Non-Producing Reservoirs"; and
Item 221, "Remaining Total Dry Gas In Non-Producing Reservoirs."

b. *Notice Schedule III, "Committed Reserves and Deliverability Estimates for All Supply Sources".* The deletions to Notice Schedule III would be as follows:

Item No.
04—Offshore Area Name
05—Offshore Area Code
13—Maximum Daily Quantity

3. *Notice "Footnote Data Page".* The Notice "Footnote Data Page" would be amended to include certain conforming format changes; the new "Footnote Data Page" would, however, report essentially the same data as the Notice version.

C. Instructions

The definitions and instructions accompanying Form No. 15 would be clarified and revised to conform with the changes proposed for the form itself.

In addition, the Supply Type Codes, Supply Class Codes and Supply Term Codes would be standardized by use of three and four letter abbreviations; the Geologic Codes would be deleted in their entirety, because they are no longer essential to reporting; the Pipeline System Map requirement would be clarified so that field maps which have not been substantially revised since they were last filed with a Form No. 15 report would not have to be submitted with a new report; and an example of a completed Schedule II, in

the new format, would be included in the instructions as a guide for respondents who must complete that schedule. The magnetic tape instructions would be amended; computer responses to the form would be required in the new format. Accordingly, magnetic tape responses and hard copy printouts would both be reported under the new format.

III. Amendments to Commission Regulations

While the format of Form No. 15 and the requirements set forth in the Form's various schedules have been markedly changed in response to public comment, the amendments to §§ 260.7 and 260.7a to implement these changes would be essentially the same as those proposed in the August, 1980 Notice of Proposed Rulemaking. The only significant proposed changes would be the following:

Section 260.7(b)(1)(ii) of the August proposed rule provides that certain interstate pipelines are required to file only specific portions of Form No. 15, including Schedule III. Because Schedule III would be consolidated with Schedule II in the new format, these pipelines would, instead, be required to file Schedule II.

Section 260.7(b)(ii)(A) would be clarified to provide that the Identification Schedule, the Synopsis of Gas Supply and Schedule II of Form No 15 shall be filed by each interstate pipeline with total remaining recoverable gas reserves that are owned or controlled by the pipeline pursuant to producer contracts and amount to less than 50 billion cubic feet at the end of the reporting year. The August Notice provided for such filings from each interstate pipeline with gas reserves owned and controlled by producers amounting to less than 50 billion cubic feet at the end of the reporting year.

Finally, § 260.7a would be corrected to provide that each interstate pipeline which transports gas for another company in interstate commerce shall file a statement which includes the name and address of each company for which it transports gas. The August Notice inadvertently provided that the interstate pipeline which transports gas for *another interstate pipeline* would be required to file this statement.

In addition, the Commission would also amend its regulations at § 157.14 to provide for the reporting of information about individual reservoirs as it relates to an application for a certificate of public convenience and necessity. § 157.14 provides requirements for exhibits to be attached to applications for certificates of public convenience and necessity and for orders permitting and approving abandonment under section 7 of the Natural Gas Act.) *Exhibit H, Total Gas Supply Data* (§ 157.14(a)(10)(vi) provides for the filing of certain information in addition to the Form No. 15. Under the current regulations, a pipeline company which is required to report gas supply and deliverability data as part of an application, can comply with the requirement by filing information reported in Schedules II and III respecting individual reservoirs. Although the reporting of individual reservoir data is proposed to be eliminated from the annual Form No. 15 report by this Revised Notice of Proposed Rulemaking, the Commission would still require information about these reservoirs in processing individual applications. Subclause (vi) of *Exhibit H* would, therefore, be amended to provide for the reporting of such information.

IV. Written Comment Procedures

The Commission invites interested persons to submit written data, views and other information concerning the matters set out in this Notice. An original and 14 copies of such comments should be filed with the Commission by May 4, 1981. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should reference Docket No. RM80-69.

All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426 during regular business hours.

(Department of Energy Organization Act, 42 U.S.C. 7101–7352; Natural Gas Act, 42 U.S.C. 717–717w; Natural Gas Policy Act, 15 U.S.C. 3301–3432; E.O. 12009, 3 CFR 1977 Comp., p. 142)

In consideration of the foregoing, the Commission proposes to amend Form No. 15 as set forth in Attachment A, and Parts 157 and 260 of Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

1. In §157.14, paragraph (a)(10)(vi) is revised in the fourth sentence, to read as follows:

§ 157.14 Exhibits.

(a) * * *

(10) * * *

(vi) * * * In those instances, the pipeline company must file detailed gas supply and deliverability information, including a summary of the remaining recoverable salable gas reserves in each reservoir for each source of supply reported, all factors used for the reserve estimate in each individual reservoir and a 10-year deliverability projection for each supply source.

* * * * *

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

2. Section 260.7 is revised to read as follows:

§ 260.7 FERC Form No. 15, Interstate pipelines' annual report of gas supply.

(a) *Prescription.* The form of Interstate Pipelines' Annual Report of Gas Supply, designated herein as FERC Form No. 15, is prescribed for the year 1981 and thereafter.

(b) *Filing requirements.* (1) *Who must file.* (i) *Generally.* All interstate pipeline companies, as defined by section 2(15) of the Natural Gas Policy Act (15 U.S.C. 3302(15)), shall prepare, and file in accordance with the instructions in Form No. 15, an original and four copies of FERC Form No. 15, unless excepted under clause (ii).

(ii) *Exceptions.* The following interstate pipelines shall prepare and file with EIA and original and four copies of only the Identification Schedule (with Certification), the "Synopsis of Gas Supply," and Schedule II of FERC Form No. 15:

(A) Each interstate pipeline with total year-end remaining recoverable gas reserves that are owned by such pipeline, or controlled by such pipeline pursuant to producer contracts, and that amount to less than 50 billion cubic feet of natural gas at the end of any reporting year; or

(B) Each interstate pipeline that purchases its entire supply of natural gas from other interstate pipelines subject to the provisions of this section, or from foreign suppliers.

(2) *When to file.* Such reports shall be filed on or before April 1 for each calendar year ending December 31 of the previous year.

3. Section 260.7a is revised to read as follows:

§ 260.7a Annual statement of gas transported by interstate pipelines for other interstate pipelines.

Each interstate pipeline, as defined by section 2(15) of the Natural Gas Policy

Act (15 U.S.C. 3302(15)), which only transports natural gas for another company in interstate commerce subject to the provisions of this section, shall prepare, and file in accordance with the requirements in Form No. 15, an original and four copies of a statement which contains the name and address of each such company for which it transports the gas. Such statement shall be filed on or before April 1 for each calendar year ending December 31 of the previous year.

¶ 32,127 Procedures for Operator Protests Regarding Stripper Well Natural Gas

46 F. R. 21192 (April 9, 1981).

18 CFR Parts 271 and 274

[Docket No. RM81-25]

Procedures for Operator Protests Regarding Stripper Well Natural Gas

Issued April 3, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission is proposing to amend its regulations implementing section 108 of the Natural Gas Policy Act of 1978 to establish procedures to be followed in filing motions contesting a notice to disqualify a well from section 108 status.

DATES: Written comments are due by May 8, 1981. Requests for public hearing are due by April 24, 1981.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Dan White, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-357-8066.

Issued April 3, 1981.

In the matter of procedures for operator protests regarding stripper well natural gas, Docket No. RM81-25, notice of proposed rulemaking.

I. Introduction

In its regulations, the Federal Energy Regulatory Commission (Commission) has established rules implementing section 108 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3318), which establishes the maximum lawful price and criteria for qualifying stripper well natural gas. The Commission is proposing herein to amend its regulations to establish the procedures to be followed in filing motions contesting a notice to disqualify a well from section 108 status.

II. Discussion

Title I of the NGPA prescribed maximum lawful prices for natural gas. Gas produced from qualified stripper wells is eligible for a comparatively high price under the NGPA.

To qualify as a stripper well, a well must produce no more than an average of 60 Mcf of non-associated natural gas per production day during any 90-day production period. To maintain qualification for the section 108 price a stripper well may not exceed certain production rate limitations contained in § 271.805 of the Commission's regulations. If the well produces natural gas at a rate exceeding the production limitation, the operator and purchaser are required to submit notices of disqualification from stripper status. If a purchaser files a notice of disqualification and the operator does not agree with the purchaser, the operator can contest a purchaser's notice of disqualification by filing a motion in accordance with § 271.805(b)(1)(i) of the regulations. Presently, the regulations do not provide filing requirements and procedures whereby a jurisdictional agency and the Commission shall consider such a motion. This rule proposes appropriate filing requirements and procedures.

III. Summary of Proposed Regulations

The proposed rule would amend § 274.206 to provide filing requirements for a motion contesting a notice of disqualification. Essentially, the movant would be required to reference the initial determination qualifying the well for stripper status and the notice of disqualification and would be required

to provide a statement summarizing the reasons why the well should not be disqualified, accompanied by any supporting documentary evidence.

The proposed rule would further amend § 271.806 to provide that a jurisdictional agency shall treat a motion contesting a notice of disqualification as it would treat an application for initial determination. The jurisdictional agency would make a determination on the motion and, within 15 days of the date of determination, would give written notice to the Commission in accordance with § 274.104.

The procedures for Commission review of a jurisdictional agency determination on a motion contesting a notice of disqualification would be the same as those governing review of well category determinations under § 275.202.

Thus, under the proposed amendments, the Commission would have 45 days after receipt of the determination to act on the jurisdictional agency determination; if no action were taken by the Commission within the 45-day period, the jurisdictional agency determination would become final.

IV. Public Procedure

A. Written Comments

Interested persons are invited to submit comments, data, views, or arguments with respect to this proposed rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should refer to Docket No. RM81-25. An original and 14 copies should be filed. All comments received prior to 4:30 p.m., May 8, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file that has been established in this docket. This file is available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

B. Public Hearing

Interested persons may request an opportunity for oral presentation of their views at a public hearing. Requests for a hearing should be submitted no later than April 24, 1981, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM81-25. If a public hearing is held in this docket, the time and place will be announced by May 8, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission proposes to amend Parts 271 and 274 of Subpart H, Chapter I, Title 18, Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 271—CEILING PRICES

1. Section 271.806 is amended by redesignating paragraphs (b) and (c) as paragraphs (c) and (d), respectively and by adding new paragraph (b), to read as follows:

§ 271.806 Jurisdictional agency determinations and Commission review.

* * * * *

(b) *Motion contesting a notice of disqualification.* The jurisdictional agency shall treat a motion contesting a notice of disqualification under § 271.805(b)(1)(i) as if it were an application for initial determination and shall comply with the applicable provisions of § 274.206(f) Subpart A of Part 274.

* * * * *

2. Section 271.806 is amended in newly designated paragraph (c) by inserting the words "or (b)" after the words "under paragraph (a)".

PART 274—DETERMINATIONS BY JURISDICTIONAL AGENCIES

3. Section 274.206 is amended by adding a new paragraph (f), to read as follows:

§ 274.206 Stripper well natural gas.

* * * * *

(f) *Motion contesting a notice of disqualification.*

For the purposes of a determination under § 271.806(b), on a motion contesting a notice of disqualification, the operator shall file:

(1) The names and addresses of the operator and purchaser(s);

(2) An identification of the well and accurate reference to;

(i) The original determination qualifying the well as a stripper well; and

(ii) The notice of disqualification filed by the purchaser pursuant to § 271.805(a);

(3) A statement summarizing the reasons why the well should not be disqualified;

(4) Any documentary evidence that supports the statement made pursuant to subparagraph (3);

(5) A statement, under oath, that all of the information contained in the motion is true to the best of the operator's information, knowledge, and belief; and that the motion has been served on the Commission and on the purchaser(s); and

(6) If the jurisdictional agency so requires, certified copies of records relied on by the operator including copies of the agency's official files.

¶ 32,128 High-Cost Gas Produced From Tight Formations (Alabama-1)

46 F. R. 22004 (April 15, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Alabama-1)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under Section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the State Oil and Gas Board of Alabama that the Basal Pennsylvanian Sand Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on May 11, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on April 24, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307 or John Bassett/Ting Chin, (202) 357-8589/8595.

SUPPLEMENTARY INFORMATION:

Issued April 9, 1981.

I. Background

On March 25, 1981, the State Oil and Gas Board of Alabama (Alabama) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Basal Pennsylvanian Sand Formation in Jefferson, Walker, and Tuscaloosa Counties, Alabama, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Alabama's recommendation that the Basal Pennsylvanian Sand Formation be designated a tight formation should be adopted. Alabama's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Alabama recommends that the basal sandstones of the Pottsville series beneath the Black Creek coal seam of the Pennsylvanian period (referred to as the "Basal Pennsylvanian Sand Formation") found in Townships 14, 15 and 16 South, Ranges 2, 3, and 4 West and Townships 15, 16, 17, and 18 South, Ranges 5, 6, and 7 West in Jefferson, Walker, and Tuscaloosa Counties, Alabama, be designated as a tight formation.

The top of the recommended formation lies below the Black Creek coal seam and extends to the base of the Pennsylvanian series. The Basal Pennsylvanian Sand Formation is identified in the Calhoun-Tutwiler Mead 12-8 well commencing at 700 feet and extending to a depth of 1970 feet. The sands in the formation are massive and vary in thickness from 300 feet to over 600 feet.

III. Discussion of Recommendation

Alabama claims in its submission that evidence gathered and presented at a public hearing in support of this recommendation demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Alabama further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Alabama that the Basal Pennsylvanian Sand Formation, as described and delineated in Alabama's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before May 11, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Alabama—1), and should give reasons including supporting data for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission.

Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than April 24, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Alabama's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (46) to read as follows:

§ 271.703 Tight Formations.

* * * * *

(d) Designated tight formations. The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(25) through (45) [Reserved].

(46) *Basal Pennsylvanian Sand Formation in Alabama.* RM79-76 (Alabama—1).

(i) *Delineation of Formation.* The Basal Pennsylvanian Sand Formation is found in Townships 14, 15 and 16 South, Ranges 2, 3, and 4 West and

Townships 15, 16, 17, and 18 South, Ranges 5, 6, and 7 West in Jefferson, Walker, and Tuscaloosa Counties, Alabama.

(ii) *Depth.* The Basal Pennsylvanian Sand Formation is a series of massive sands 300 feet to 600 feet thick extending from the base of the Black Creek coal seam, the lowest commercial coal seam in the area, to the base of the Pennsylvanian series.

¶ 32,129 Definition of Agricultural Use in Commission's Incremental Pricing Regulations

46 F. R. 23487 (April 27, 1981).

18 CFR Part 282

[Docket No. RM81-17]

Definition of Agricultural Use in Commission's Incremental Pricing Regulations

Issued April 20, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission is proposing to amend its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432). Specifically, it proposes to expand the list of agricultural uses of natural gas set forth in § 282.202(a)(1)(iii), which are exempt from incremental pricing, by adding certain stages in the manufacture of gelatin, glue and carboxy methyl cellulose (CMC).

DATES: Written Comments are due by May 29, 1981. Requests for public hearing are due by May 15, 1981. Public hearing, if requested, will be held on June 9, 1981.

ADDRESS: Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Robert Fleishman, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, DC 20426 (202) 357–8270; or

Alice Fernandez, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, DC 20426 (202) 357–9095

In the matter of a definition of agricultural use in § 282.202(a) of the Commission's Incremental Pricing Regulations, Docket No. RM81–17, notice of proposed rulemaking.

Issued April 20, 1981.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432). Specifically, it proposes to expand the list of agricultural uses of natural gas set forth in § 282.202(a)(1)(iii), which are exempt from incremental pricing, by adding certain stages in the manufacture of gelatin, glue and carboxy methyl cellulose (CMC).

II. Background

Title II of the NGPA requires the Commission, within certain guidelines, to institute and administer an incremental pricing program. The program is designed to pass through, by surcharge, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA to certain industrial facilities that use natural gas as a boiler fuel. However, industrial facilities that use natural gas as a boiler fuel for an agricultural use, as defined in section 206(b)(3) of the NGPA, are currently exempt from the incremental pricing program.[1] Section 206(b)(3) defines "agricultural use" as follows:

> (3) Agricultural use defined.—For purposes of this subsection, the term "agricultural use", when used with respect to natural gas, means the use of natural gas to the extent such use is—
>
> (A) For agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or
>
> (B) As a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

[1] Docket No. RM80–29, Order No. 83, issued May 7, 1980, 45 FR 33601 (May 20, 1980).

The definition of "agricultural use" originally proposed by the Commission to implement this exemption was limited to those uses of natural gas certified as "essential agricultural uses" by the Secretary of Agriculture pursuant to Section 401 of the NGPA.[2] In response to public comments, the Commission issued regulations which expanded this definition to include the Standard Industrial Classification (SIC) Codes representing the processing and finishing of natural fiber by the textile industry.[3] The regulations were further amended on rehearing to include the SIC Codes for wood processing.[4] Subsequently, the Commission amended § 282.202(a) after considering several requests for inclusion of specific uses of natural gas within the definition of "agricultural use."[5]

On February 13, 1981, Peter Cooper Corporations (Peter Cooper) filed a petition in this docket for a rulemaking to further amend § 282.202(a) to include the manufacture of glue, gelatin and nitrogenous fertilizer. The Commission has consistently considered whether particular SIC Codes, or particular uses within such SIC Codes, should be included in § 282.202(a) in the context of rulemaking proceedings. Therefore, Peter Cooper's petition for a rulemaking to consider additional SIC Codes is granted. On January 9, 1981, Hercules Incorporated (Hercules) filed a request for an interpretation that the manufacture of CMC is natural fiber processing and that § 282.202(a) be interpreted to include the manufacture of CMC.[6] The requests of both Peter Cooper and Hercules will be considered in this docket.

The Commission urges all interested persons to submit any other proposed amendments to § 282.202(a) in this rulemaking docket, within the time specified in Part VII of this notice for the filing of written comments. The Commission feels that most persons who would request such amendments to § 282.202(a) either have already done so, or can do so in the context of this proceeding. Accordingly, it anticipates that it will not allocate Commission or staff time to consideration of similar additional rulemaking proceedings in the near future.

III. Summary of Requests and Proposed Revisions to Regulations

A. *SIC Code 2899 Chemicals and Chemical Preparations, Not Elsewhere Classified* (the manufacture of gelatin from animal hides by natural fiber processing only)

Peter Cooper seeks to amend § 282.202(a)(1)(iii) to include SIC Codes that cover the manufacture of gelatin on the basis that it involves natural fiber processing, agricultural production and food processing. Regarding natural fiber processing, Peter Cooper claims that the manufacture of gelatin falls within that category because gelatin is derived from animal hides which are natural fiber.

Based on Peter Cooper's assertions in its petition, the Commission believes that the manufacture of gelatin from animal hides may be natural fiber processing. In the final rule issued in Docket No. RM79–14, the Commission determined that animal hides are a natural fiber.[7] Gelatin, as it is manufactured in the manner described by Peter Cooper, appears to be derived

[2] Proposed Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978, Docket No. RM79–14, issued June 5, 1979, 44 FR 33099 (June 8, 1979). See also Docket No. RM80–75, Interim Rule, issued October 6, 1980, 45 FR 67276 (October 9, 1980).

[3] Docket No. RM79–14, Order No. 49, issued September 28, 1979, 44 FR 57726 (October 5, 1979).

[4] Docket No. RM79–14, Order No. 49–A, issued December 27, 1979, 45 FR 767 (January 3, 1980).

[5] Docket No. RM80–48, Order No. 114, issued December 5, 1980, 45 FR 82915 (December 17, 1980).

[6] Commission Staff advised Hercules that it would be necessary to amend the regulations to include an SIC Code to cover such manufacture, since § 282.202(a) could not be construed to cover Hercules manufacture of CMC. Hercules agreed that its request for interpretation should be treated as a request for a rulemaking and included in the rulemaking docket opened to consider Peter Cooper's petition for rulemaking.

[7] SIC Code 3111 Leather Tanning and Finishing.

from parts of animal hides, and therefore the manufacture of gelatin probably involves the processing of natural fiber. Accordingly, the Commission proposes to amend the definition of agricultural use in § 282.202(a)(1)(iii) to include SIC Code 2899 for the manufacture of gelatin to the extent that it is manufactured from animal hides by natural fiber processing. The Commission notes that if the manufacture of gelatin from animal hides involves several processing stages in which the animal hides are converted to an intermediate material and then to gelatin, it is possible that the further processing of intermediate material is no longer natural fiber processing. In that case, the manufacturer would be required to file an estimation methodology setting forth that portion of gas usage which is exempt as an agricultural use and that portion which is not exempt. The Commission solicits comment that detail the stages in the manufacture of gelatin so it can determine which stages, if any, would not qualify as natural fiber processing.

The Commission rejects the argument that the manufacture of gelatin is agricultural production, because such manufacture is at least one step removed from the actual production of an agricultural product (animal hides). The Commission stated in the final rule issued in Docket No. RM80–48 regarding manufacturing operations in the agricultural production chain, that

> These operations are at least one step removed from the actual production * * * of the agricultural product itself. The definition of agricultural use in § 282.202(a) as it relates to "agricultural production" is generally limited to those SIC Codes representing the on-farm use of natural gas for the production of crops or the raising of livestock.*

Since the Commission is proposing to add the manufacture of gelatin to the list of agricultural uses, on the basis of, and to the extent that, its manufacture may be natural fiber processing, it does not reach at this time the question of whether this manufacture of gelatin is food processing under section 206(b) of the NGPA. However, if the manufacture of gelatin includes the processing of an intermediate material that is not natural fiber, comments are sought on whether the manufacture of gelatin is food processing.

B. *SIC Code 2891 Adhesives and Sealants* (the manufacture of glue from animal hides by natural fiber processing only)

Peter Cooper petitions the Commission to amend § 282.202(a) to include SIC Codes that cover the manufacture of glue, because it involves the processing of animal hides and, as such, qualifies as natural fiber processing and agricultural production.

Peter Cooper asserts that, because glue is derived from a natural fiber, animal hides, it constitutes natural fiber processing. For the reasons the Commission stated in its discussion of the manufacture of gelatin, the Commission proposes to amend the definition of agricultural use in § 282.202(a)(1)(iii) to include SIC Code 2891 for the manufacture of glue from animal hides by natural fiber processing only. The Commission solicits comments that detail the stages in the manufacture of glue so it can determine which stages, if any, would not qualify as natural fiber processing.

The Commission rejects the argument that the manufacture of glue is agricultural production for the same reason discussed above in Part A of this notice.

C. *SIC Code 2873 Nitrogenous Fertilizer*

Peter Cooper petitions the Commission to amend § 282.202(a) to include SIC Codes covering the manufacture of nitrogenous fertilizer on the basis that it is agricultural production and natural fiber processing.[9] Nitrogenous fertilizer, as described by Peter Cooper, is derived from tankage, a residue from the processing of animal hides which consists, in part, of animal hair. Peter Cooper asserts that the manufacture of

*Docket No. RM80–48, Order No. 114, 45 FR at 62917–8.

nitrogenous fertilizer is agricultural production because it is "the exploitation of perishable animal materials" and further asserts that, because animal hair is fibrous, the manufacture of nitrogenous fertilizer is natural fiber processing.

The Commission rejects the argument that the manufacture of nitrogenous fertilizer is agricultural production for the same reason discussed above in Part A of this notice.

The Commission also rejects the argument that the manufacture of fertilizer is natural fiber processing because tankage, although it contains animal hair, is not substantially comprised of natural fiber, but is a residue from the processing of animal hides. Therefore, it is one-step removed from natural fiber processing.

In conclusion, the Commission does not believe that the use of natural gas as a boiler fuel to manufacture nitrogeneous fertilizer is an agricultural use. Accordingly, the Commission does not propose at this time to add SIC Code 2873 to § 282.202(a)(1)(iii), however, the Commission requests comments on this preliminary conclusion. Specifically, the Commission requests comments on what proportion of tankage is animal hair and on whether the presence of animal hair is essential to the production of the nitrogenous fertilizer.

D. *SIC Code 28692 Miscellaneous Acrylic Chemicals and Chemical Products, Excluding Urea* (the manufacture of carboxy methyl cellulose from wood pulp only).

Hercules requests that § 282.202(a)(1)(iii) be determined to include the manufacture of CMC as natural fiber processing. Hercules states that CMC is manufactured either from wood pulp or from chemical cotton. The Commission determined in Docket No. RM 80-48 that wood pulp is a natural fiber and agrees with Hercules that the manufacture of CMC from wood pulp is natural fiber processing. However, since the Commission has not previously determined that chemical cotton is a natural fiber, it does not propose at this time to amend the regulation to include such manufacture. The Commission, however, specifically requests comments that detail the stages of manufacture of CMC from chemical cotton,and that address the question of whether any of the stages are natural fiber processing.

Accordingly, the Commision proposes at this time to amend the definition of agricultural use in § 282.202(a)(1)(iii) to include SIC Code 28692 for the manufacture of CMC from wood pulp only.

IV. Summary of Proposed Regulations

For the reasons stated above, the Commission proposes to amend § 282.202(a)(1)(iii) of its regulations to include the following SIC Codes:

SIC Code 28692 Miscellaneous Acrylic Chemicals and Chemical Products, Excluding Urea (manufacture of carboxy methyl cellulose from wood pulp only);

SIC Code 2891 Adhesives and Sealants (the manufacture of glue from animal hides by natural fiber processing only); and

SIC Code 2899 Chemicals and Chemical Preparations, Not Elsewhere Classified (Chemical cotton—processed cotton linters and the manufacturer of gelatin from animal hides by natural fiber processing only).

V. Effect of Rule

The amendment proposed herein, if adopted as a final rule, would only grant an exemption to the subject uses of natural gas until such time as the permanent exemption rule pursuant to section 206(b)(2) of the NGPA becomes effective. At that time, all exemptions encompassed by § 282.202(a) will become subject to the provisions of the permanent rule.

VI. Certification of No Significant Economic Impact

The Regulatory Flexibility Act [10] (RFA) requires certain statements,

[9] Peter Cooper requests that its use of natural gas to manufacture nitrogenous fertilizer be exempt as an "agricultural use" under section 206(b)(3)(A) because its uses natural gas as boiler fuel, and not as a proces fuel or feedstock.

[10] 5 U.S.C. 601-612. (Pub. L. No. 96-354, September 19, 1980).

descriptions, and analyses of proposed rules that will have "a significant impact on a substantial number of small entities."

Pursuant to 5 U.S.C. 605(b) the Commission finds that the provisions of the RFA do not apply to this rulemaking. If promulgated, this rulemaking would exempt certain industrial facilities from the incremental pricing program based upon their agricultural use of natural gas. Therefore, the effect of this rulemaking is to relieve certain industrial facilities from the surcharge imposed by the incremental pricing program. As such, this rulemaking does not impose any regulatory or administrative burdens upon a significant number of small entities, nor does it require an expenditure of resources by such entities. The Commission hereby certifies that this rulemaking, if promulgated, will not have a significant economic impact on a substantial number of small entities, as defined in the RFA.

VII. Public Comment Procedures

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this notice. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should reference Docket No. RM81–17. An original and 14 copies should be filed. All comments received on or before Friday, May 29, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket. This file is available for public inspection through the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426 during regular business hours.

B. Public Hearing

Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for an oral hearing should be submitted no later than Friday, May 15, 1981, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM81–17. If any requests are received by that time, the hearing will be held on Tuesday, June 9, 1981, at the above address, and will be announced by Monday, May 25, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; E.O. 12009, 42 CFR 46267 (1978))

In consideration of the foregoing, the Commission proposes to amend § 282.202(a)(1)(iii) of Part 282, Subchapter I, Chapter I, Title 18, *Code of Federal Regulations*, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.202 is amended by adding the following entries to (a)(1)(iii).

§ 282.202 Definitions.

(a)(1) "Agricultural use" means: * * *

(iii) Any use of natural gas determined by the Commission to be an agricultural use and listed below; *provided that*, the use of such natural gas in textile operations is limited as set forth below to the production or processing of natural fiber: *Industry SIC No. and Industry Description.*

* * * * *

Natural Fiber Processing

* * * * *

28692 Miscellaneous Acrylic Chemicals and Chemical Products, Excluding Urea (manufacture of carboxy methyl cellulose from wood pulp only).

[The next page is 33,177-3.]

2891 Adhesives and Sealants (the manufacture of glue from animal hides by natural fiber processing only).

2899 Chemicals and Chemical Preparations, Not Elsewhere Classified (Chemical cotton—processed cotton linters and the manufacture of gelatin from animal hides by natural fiber processing only).

HOLDEN, Commissioner, *concurring:*

(Issued May 8, 1981)

My comment here relates to one point only.

The Commission has rejected the argument that the manufacture of nitrogenous fertilizer from tankage, a residue from the processing of animal hides, which consists, in part, of animal hair, is "agricultural production". The basis of Order No. 114 emphasizes, as a general proposition, that the more remote an operation is from on-farm activity, the less likely that operation can be defended as "agricultural".

However, it is possible to conceive of a logical argument that would yield a different result.

In my view, the manufacture of fertilizer, using tankage as described, turns what would be a waste into a resource. In this sense, it may be part of an agricultural cycle, which runs from farm to fertilizer to farm again. Off-farm or not, it might intelligently be regarded as "agricultural".

It would be rational to propose for comment, therefore, a rule which included the manufacture as described.

However, the Commission does seek comment on whether its present interpretation of Order No. 114 is well founded. The practical result would be the same, i.e., to allow comment on how to treat fertilizer, although from a different perspective.

I, therefore, concur.

¶ 32,130 Incremental Pricing: Adoption of Single-Tier Alternative Fuel Price Ceiling

46 F. R. 23947 (April 29, 1981).

18 CFR Part 282

Incremental Pricing; Adoption of Single-Tier Alternative Fuel Price Ceiling

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to amend its regulations on incremental pricing under Title II of the Natural Gas Policy Act of 1978. Because of problems relating to the calculation of price ceilings and the potential wasteful capital investment inherent in a three tier system, the Commission proposes to amend §§ 282.402 and 282.403 to permanently establish a single-tier, high sulfur No. 6, alternative fuel price ceiling.

DATES: Written comments on the proposed rule are due on May 22, 1981. Written requests for a public hearing are due on May 7, 1981.

ADDRESS: Comments and requests for hearing must be filed with: the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Thomas P. Gross, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8171, or

Ronald Leach, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-5417.

SUPPLEMENTARY INFORMATION: Issued: April 22, 1981.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). Specifically, the Commission proposes to amend §§ 282.402 and 282.403 to permanently establish a single-tier, high-sulfur No. 6, alternative fuel price ceiling.

II. Alternative Fuel Price Ceiling

A. Background

Title II of the NGPA requires the Commission, within certain guidelines, to institute and administer an incremental pricing program. The program is designed to pass through, by surcharge, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA to certain industrial facilities that use of natural gas as boiler fuel. The purpose of the program is to shield high-priority customers from the natural gas price increases permitted under Title I and to prepare the market for deregulation of natural gas pricing in 1985.

Generally, under Title II of the NGPA, the incremental pricing surcharge applicable to a particular facility is the difference between the price paid for natural gas by that facility and the price at which the facility can purchase alternative fuel. The price of the alternative fuel, the alternative fuel price ceiling, is determined in accordance with section 204(e) of the NGPA. Section 204(e)(1) provides that the alternative fuel price ceiling for an incremental pricing region is the price of No. 2 fuel oil that is determined by the Commission to be paid by industrial users in that region. Section 204(e)(2) provides that the Commission may reduce the alternative fuel price ceiling to an amount not lower than the price for No. 6 fuel oil, if it determines that the reduction is necessary to prevent an increase in rates to residential, small commercial, and other high priority customers.

On September 28, 1979, the Commission issued a rulemaking in Docket No. RM79-21 (Order No. 50) implementing section 204(e) by

establishing a three-tier system for alternative fuel price ceilings.[1] Under this system, three alternative fuel price ceilings are to be published for each incremental pricing region. The three price ceilings are calculated on the basis of sales in the region of No. 2 fuel oil, low-sulfur No. 6 fuel oil, and high-sulfur No. 6 fuel oil, respectively. The price ceiling applicable to a particular industrial boiler fuel facility is the price published for the region in which that facility is located which corresponds to the lowest priced fuel oil that the facility has the installed capability and legal authority to burn.

However, for reasons discussed below, the Commission determined that implementation of the three-tier system was inappropriate at that time, and, accordingly, also issued on September 23, 1979, a second rulemaking in Docket No. RM79-21 (Order No. 51),[2] which postponed the application of the three-tier system of alternative fuel price ceilings. Issued under the authority of section 206(d) of the NGPA, Order No. 51 provided that from January 1, 1980 until November 1, 1980, a single-tier, high-sulfur No. 6 alternative fuel price ceiling would be published for each region and would be applied to incrementally-priced industrial facilities. This single-tier system temporarily exempted industrial facilities from that portion of incremental pricing surcharges which would otherwise result from application of an alternative fuel price ceiling above the price of No. 6 high-sulfur fuel oil, regardless of the facilities' alternative fuel capabilities.

Because the Commission foresaw that the problems with the three-tier system would not be solved by November 1, 1980, the Commission subsequently issued another rulemaking in Docket No. RM79-21 (Order No. 81),[3] which extended the application of a single-tier, high-sulfur No. 6 fuel oil, price ceiling until October 31, 1981. Thus three-tier system is presently scheduled to take effect on November 1, 1981.

B. *Discussion*

The problems which have thus far induced the Commission to refrain from imposition of the three-tier system relate to the calculation of the price ceilings and to the potential wasteful capital investment inherent in a three-tier system.

With respect to the calculation of the price ceilings, the Commission and its staff, in conjunction with the Energy Information Administration (EIA),[4] have devoted a great deal of time and effort to analysis of the appropriate incremental pricing regions for which price ceilings should be calculated and to analysis of the methodology which would yield price ceilings that would most accurately reflect the price of alternative fuel in each region.[5] For reasons discussed therein, the Commission in Order No. 50 established that the current incremental pricing regions are the 48 continental states. Based upon its analysis and upon its experience to date in administering the incremental pricing program, the Commission has determined that, in view of the present fluctuations in the oil market, even under the single-tier system there are serious difficulties in developing a methodology which would yield an alternative fuel price ceiling that accurately reflects the current price of fuel oil, on a monthly basis, in the individual states. The difficulties primarily center around the requirement that the price ceiling for a particular

[1] Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing under the Natural Gas Policy Act of 1978, Docket No. RM79-21, Order No. 50, issued September 28, 1979, 44 FR 57754 (October 5, 1979).

[2] Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil, Docket No. RM79-21, Order No. 51, issued September 28, 1979, 44 FR 57778 (October 5, 1979).

[3] Rule Further Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil and Applying Ceiling Prices to Forty Eight Incremental Pricing Regions, Docket No. RM79-21, Order No. 81, issued May 7, 1980, 45 FR 31300 (May 13, 1980).

[4] The Energy Information Administration of the Department of Energy is responsible for the collection of data and the calculation and publication of the alternative fuel price ceilings.

[5] *See, e.g.*, Notice of Inquiry, Docket No. RM79-21, issued November 4, 1980, 45 FR 74505 (November 10, 1980).

state must be calculated on the basis of the sale prices of the fuel oil in that state for a particular month. In states where there have been only a few sales of fuel oil in that month, the price ceiling computed on the basis of so few sales can lead, and has led, to significant disparities in price ceilings in neighboring states.[6] Such disparities generally indicate that the price ceiling do not always accurately reflect the actual market price of the alternative fuel, since many facilities could buy the alternative fuel in the neighboring state at a lower price than the price ceiling calculated for their own state. Commission experience and comments received in another docket [7] indicate that incrementally priced facilities are sensitive to increases in price ceilings. The Commission, therefore, is concerned about disparities that might lead to fuel switching and commensurate load loss. Such load loss could result in shifting a higher proportion of fixed system costs to high-priority gas customers, thereby defeating one purpose of the incremental pricing program, the partial shielding of high-priority users from higher natural gas costs.

Although the Commission has attempted to mitigate these difficulties by revising its methodology to computing price ceilings,[8] it believes that implementation of the three-tier system, requiring the calculation of price ceilings for three fuel oils on a monthly basis for each state, would create additional disparities and would exacerbate the problems associated with the calculation of the price ceilings. In view of the problems associated with calculation of the alternative fuel price ceilings under the single-tier system and the foreseeable multiplication of those problems under the three-tier system, the Commission has concluded that an accurate, equitable, and administrable three-tier price ceiling program has not yet been, and may not be able to be, developed.

In addition to the problems associated with the calculation of the price ceilings, the Commission is also concerned, as noted in earler rulemakings,[9] that implementation of the three-tier system, to a certain extent, would be ineffective. As discussed above, incrementally priced facilities are sensistive to even small increases in alternative fuel price ceilings. The Commission believes that the substantial increases in price ceilings which would result from implementation of the three-tier system would cause facilities that do not now possess the capability for using No. 6 fuel oul as an alternative fuel to make substantial investments to acquire that capability, solely for the purpose of qualifying for a lower incremental pricing surcharge. Such actions would result in potential wasteful capital investments for equipment not likely to be used and would undercut the purpose of the three-tier system by permitting, in effect, facilities whose only alternative fuel is higher-priced No. 2 fuel oil to be incrementally priced at the lower, No. 6 fuel oil price.

The Commission recognizes that, in the short term, a three-tier system theoretically would maximize the recovery of incremental costs from industrial facilities by maximizing the surcharges absorbed by those facilities. However, it believes that this benefit is outweighed by the problems discussed above. Furthermore, in the long term, the benefit may be illusory, due to the fuel switching and installation of unnecessary lower-priced fuel oil burning capability. Accordingly, the

[6] *See, e.g.*, Rule Adopting Revised Alternative Fuel Price Ceilings for the State of Kentucky, Interim Rule, Docket No. Rm81-9, issued December 24, 1980, 46 FR 2038 (January 8, 1981).

[7] See comments submitted in response to a Notice of Inquiry in Docket No. RM79-21, issued November 4, 1980, 45 FR 74505 (November 10, 1980) and Rule Adopting Revised Alternative Fuel Price Ceilings for the State of Kentucky, Interim Rule, Docket No. RM81-9, issued December 24, 1980, 46 FR 2038 (January 8, 1981).

[8] Regulations Implementing Alternative Fuel Price Ceilings for Incremental Price Under the Natural Gas Policy Act of 1978, Interim Rule, Docket No. RM79-21, issued March 2, 1981, 46 FR 15498 (March 6,1981).

[9] *See, e.g.*, Order Nos. 51 and 81, *supra*.

Commission is proposing a rule that would establish, on a permanent basis, the current single-tier system, based on the price of high-sulfur No. 6 fuel oil, for all incrementally priced facilities.

Section 206(d) of the NGPA provides that the Commission "may by rule or order, provide for the exemption, in whole or in part, of any other incrementally priced industrial facility or category thereof" from the incremental pricing program. The proposed rule would be issued pursuant to section 206(d) as were Order Nos. 51 and 81, which postponed implementation of the three-tier system. However, interested persons are encouraged to submit comments and data relating to the required findings under section 204(e) for implementation of a single-tier system.

C. Summary of the Proposed Rule

The proposed rule would amend §§ 282.402 and 282.403 of the Commission's current regulations. Current § 282.402(a), which states that a facility's alternative fuel capability is to be determined in accordance with § 282.403, would be deleted. Current § 282.402(b)(1), which provides for the determination and publication of alternative fuel price ceilings based on sales of No. 2 fuel oil, low-sulfur No. 6 fuel oil and high-sulfur No. 6 fuel oil, would also be deleted.

Current § 282.402(b)(2), with two changes, would become the general rule is revised § 282.402. The changes are: (1) the addition of a phrase to specify that the published price ceiling is the price ceiling for high-sulfur No. 6 fuel oil; and (2) the deletion of the clause relating to the alternative fuel capability of the facility. Thus, revised § 282.402 would generally provide that the alternative fuel price ceiling applied to a non-exempt industrial boiler fuel facility for any month is the ceiling which is published for high-sulfur No. 6 fuel oil for that month for the incremental pricing region in which the facility is located.

Current § 282.402(c), which provides for the temporary imposition of a single-tier system, would be deleted.

Current § 282.403(a) provides that an incrementally priced facility is deemed to have the capability of using No. 2 fuel oil as an alternative to natural gas, unless the facility is certified to have the capability to burn other specified fuel oils. Paragraphs (b) through (i) of current § 282.403 establish the requirements for obtaining certification. Since under the proposed rule, the alternative fuel price ceiling applicable to all facilities would be high-sulfur No. 6 fuel oil, current § 282.403 would be deleted in its entirety.

III. Congressional Review

Rules issued pursuant to section 206(d) of the NGPA are required to be submitted to Congress prior to becoming effective. Accordingly, if the Commission issues a final rule in this docket, as proposed, under authority of section 206(d), the rule would be transmitted to each House of Congress and would take effect after 30 days from the transmittal date of continued session of Congress (as set forth in section 507(b) of the NGPA), unless either House of Congress adopts a resolution of disapproval within the 30-day period.

Congress will therefore have the opportunity to review the considerations inherent in the choice between a single-tier or three-tier system. If Congress disapproves this exemption, the three-tier system will go into effect.

IV. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) [19] requires certain statements, descriptions and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities."

Pursuant to section 605(b) of the RFA, the Commission finds that the provisions of that Act do not apply to this rulemaking. If promulgated, this

[19] 5 U.S.C. 601-612 (Pub. L. 96-354, September 19, 1980).

rulemaking would permanently establish the program already in effect for alternative fuel price ceilings. The program would continue to use the single-tier price ceiling (at the level of high-sulfur No. 6 fuel oil) and would not impose any additional requirements. Those who are required to comply with the filing requirements of the existing program are generally large oil dealers whose individual sales of high-sulfur No. 6 fuel oil are in excess of 4,000 gallons. Moreover, small industrial boiler fuel facilities are exempt from any incremental pricing surcharges.

Therefore, this rulemaking does not impose any regulatory or administrative burden upon small entities, nor does it require an expense of resources by such entities. For these reasons, the Commission hereby certifies that this rulemaking, if promulgated, would not have a significant impact on a substantial number of small entities.

V. Comment Procedures

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this notice. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM81-27. An original and 14 copies should be filed. All comments received on or before May 22, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., 20426, during regular business hours.

B. Public Hearing

Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for an oral hearing should be submitted no later than May 7, 1981, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM81-27. If any requests are received by that time, the Commission will give notice of the date and time of the public hearing by May 12, 1981. Interested persons may also obtain information on the public hearing by calling the Office of the Secretary of the Commission on or after that date.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.* Department of Energy Organization Act, 42 U.S.C. 7701 *et seq.* E.O. 12009, 42 CFR 46267 (1978))

In consideration of the foregoing, the Commission proposes to amend Part 282, Subchapter I of Chapter I, Title 18 of the Code of Federal Regulations, as provided below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.402 is revised to read as follows:

§ 282.402 General rule.

The alternative fuel price ceiling which shall be applied to a non-exempt industrial boiler fuel facility for incremental pricing purposes for any month shall be the ceiling which has been published for No. 6 high-sulfur fuel oil for that month, in accordance with § 282.404, for the incremental pricing region in which the facility is located, except as permitted in § 282.405.

§ 282.403 [Reserved]

2. Section 282.403 is removed and reserved.

¶ 32,131 Incremental Pricing: Elimination of 31 Metropolitan Regions

46 F. R. 23950 (April 29, 1981).

18 CFR Part 282

[Docket No. RM81-28]

Incremental Pricing: Elimination of 31 Metropolitan Regions

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to amend its regulations on incremental pricing under Title II of the Natural Gas Policy Act of 1978. Specifically, the Commission proposes to amend § 282.404 to eliminate the 31 metropolitan areas as incremental pricing regions, because they lack statistically significant data for the calculation of accurate alternative fuel price ceilings.

DATES: Written comments on the proposed rule are due on May 22, 1981. Written requests for a public hearing are due on May 7, 1981.

ADDRESS: Comments and requests for hearing must be filed with: the Office of the Secretary, 825, North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Thomas P. Gross, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8171,

Ronald Leach, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–5417.

SUPPLEMENTARY INFORMATION:

I. Introduction

The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432). Specifically, the Commission proposes to amend § 282.404 to eliminate the 31 metropolitan areas as incremental pricing regions.

II. The Metropolitan Regions

A. Background

Section 204(e) of the NGPA provides that the Commission is to designate the incremental pricing regions for which alternative fuel price ceilings are to be determined. In Order No. 50,[1] the Commission established that there are 48 incremental pricing regions corresponding to the 48 continental states. It also provided that, as of October 20, 1980, the number of regions would be expanded to 79 regions, consisting of the 48 states and 31 metropolitan regions. Subsequently, in Order No. 81,[2] the Commission deferred implementation of the metropolitan regions until October 20, 1981. Accordingly, under the current regulations, beginning on October 20, 1981, price ceilings must be determined and published for, and incremental pricing surcharges calculated on the basis of, 79 incremental pricing regions.

B. Discussion

The Commission's purpose for establishing 31 metropolitan regions in addition to the 48 state regions was to accurately reflect actual market prices which must be paid by incrementally priced facilities located in large metropolitan areas. The Commission believed that, due to circumstances peculiar to large metropolitan areas, the price at which alternative fuel would be available to facilities located in those areas might differ significantly from the price at which the fuel would be

[1] Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing under the Natural Gas Policy Act of 1978, Docket No. RM79–21, Order No. 50, issued September 28, 1979, 44 FR 57754 (October 5, 1979).

[2] Rule Further Exempting Industrial Boilder Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil and Applying Ceiling Prices to Forty-Eight Incremental Pricing Regions, Docket No. RM79–21, Order No. 81, issued May 7, 1980, 45 FR 31300 (May 13, 1980).

available to facilities located in other areas in the state. However, the Commission could not implement the metropolitan regions immediately, because the Energy Information Administration (EIA) was experiencing difficulties in calculating statistically accurate price ceilings for those regions due to insufficient oil price data.[3] The Commission therefore postponed implementation of the metropolitan regions until October 1980 to give EIA time to develop a satisfactory methodology for making the necessary calculations. When it became clear that EIA would not be able to meet the October 1980 date, the Commission postponed implementation of the metropolitan regions until October 20, 1981.

In a Notice of Inquiry in Docket No. RM79–21, the Commission explored the difficulties encountered by EIA and sought comment on the advisability, in light of the difficulties, of continuing its attempts to implement the metropolitan regions as incremental pricing regions.[4] Although some comments urged implementation for the metropolitan regions based upon the different circumstances for facilities located in those regions as compared to facilities located elsewhere in the state, other commenters, including a large trade association representing the natural gas industry, urged the Commission to eliminate the metropolitan regions. The trade association, previously an advocate of the use of the metropolitan regions, reassessed its position and concluded that lack of available data on oil prices militates against adoption of the metropolitan areas.

After more than a year's experience in administering the program with 48 incremental pricing regions and more than two years' effort in studying the advantages and disadvantages associated with implementation of the 31 metropolitan regions, the Commission believes that no benefit will be gained by adding the 31 metroplitan areas as incremental pricing regions. The lack of statistically significant data upon which to base calculations of alternative fuel price ceilings for the metropolitan regions makes the purpose for adding the regions, more accurate price ceilings, unattainable. Accordingly, the Commission is proposing to eliminate the 31 metropolitan regions, and to retain the 48 state regions, as incremental pricing regions.

C. Summary of the Proposed Rule

The proposed rule would revise § 282.404 and Appendix I to Subpart D of Part 282 of the Commission's regulations. Paragraph (a) of § 282.404, which sets the general rule for publishing alternative fuel price ceilings and lists corrections to previously published price ceilings, would not be changed by the proposed rule.

Current paragraph (b)(1) of § 282.404, which establishes the date upon which the monthly price ceilings will be published, would remain unchanged in substance by the proposed rule. Current paragraph (b)(2), which establishes the date for publication of price ceilings for the metropolitan regions, would be deleted.

Current paragraph (c)(1) of § 282.404 provides that, until publication of price ceilings for the metropolitan regions, the 48 state regions are the incremental pricing regions. The proposed rule would delete the clause referring to the metropolitan regions, thus removing any limitation on the 48 state regions as incremental pricing regions. The proposed rule would delete current paragraph (c)(2) which provides that, after the date of publication of price ceilings for the metropolitan regions, the incremental pricing regions will be the 48 state regions and the 31 metropolitan regions.

[3] The Energy Information Administration of the Department of Energy is responsible for the collection of data and the calculation and publication of the alternative fuel price ceilings.

[4] Notice of Inquiry, Docket No. RM79–21, issued November 4, 1980, 45 FR 74505 (November 10, 1980).

Appendix I to Subpart D of Part 282 lists the 31 metropolitan regions and eight multistate regions. The proposed rule would delete the list of metropolitan regions.

Finally, the map at the end of Appendix I, on which the metropolitan regions are represented, would be deleted by the proposed rule.

III. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA)[5] requires certain statements, descriptions and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities."

Pursuant to section 605(b) of the RFA, the Commission finds that the provisions of that Act do not apply to this rulemaking. If promulgated, this rulemaking would permanently establish the incremental pricing regions already in effect for which alternative fuel price ceilings are published. The program would continue to use the 48 states as regions and eliminate the 31 metropolitan areas as regions. No additional requirements would be imposed. Those who are required to comply with the filing requirements of the existing program are generally large oil dealers whose individual sales of high-sulfur No. 6 fuel oil are in excess of 4,000 gallons. Moreover, small industrial boiler fuel facilities are exempt from any incremental pricing surcharges.

Therefore, this rulemaking does not impose any regulatory or administrative burden upon small entities, nor does it require an expense of resources by such entities. For these reasons, the Commission hereby certifies that this rulemaking, if promulgated, would not have a significant impact on a substantial number of small entities.

IV. Comment Procedures

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this notice. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM81–28. An original and 14 copies should be filed. All comments received on or before May 22, 1981, will be considered by the Commission, prior to promulgation of final regulations. All writen submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

B. Public Hearing

Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for an oral hearing should be submitted no later than May 7, 1981, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM81–28. If any requests are received by that time, the Commission will give notice of the date and time of the public hearing by May 22, 1981. Interested persons may also obtain information on the public hearing by calling the Office of the Secretary of the Commission on or after that date.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.* Department of Energy Organization Act, 42 U.S.C. 7701 *et seq.* E.O 12009, 42 CFR 46267 (1978))

In consideration of the foregoing, the Commission proposes to amend Part 282, Subchapter I of Chapter I, Title 18 of the *Code of Federal Regulations*, as provided below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 282.404 is revised in paragraphs (b) and (c) to read as follows:

[5] 5 U.S.C. 601–612 (Pub. L. 96–354, September 19, 1980).

§ 282.404 Alternative fuel price ceilings.

* * * * *

(b) *Publication.* Alternative fuel price ceilings shall be published for each of the contiguous 48 states of the continental United States on or before the twentieth day of each month.

(c) *Incremental pricing regions.* The incremental pricing regions used for purposes of this part shall be each of the contiguous 48 states within the continental United States. The alternative fuel price ceilings applicable to the District of Columbia shall be the ceilings published for the State of Maryland.

2. Appendix I to Subpart D of Part 282 is revised by removing the map of the continental United States illustrating the 31 metropolitan incremental pricing regions and is further revised to read as follows:

Appendix I—Incremental Pricing Regions

The following are multistate regions which may be used by the Commission in deriving alternative fuel price ceilings for state incremental pricing regions (1) for which statistically valid samples of oil prices may be unavailable, or (2) where the Commission determines that the public interest requires use of the regional ceiling in place of the state ceiling.

Region A—New England Multistate Region

Maine	Massachusetts
New Hampshire	Connecticut
Vermont	Rhode Island

Region B—Mid-Atlantic Multistate Region

New York	Delaware
Pennsylvania	Maryland
New Jersey	

Region C—Southeastern Multistate Region

Virginia	Georgia
North Carolina	Florida
South Carolina	Alabama
Tennessee	Mississippi

Region D—Midwestern Miltistate Region

West Virginia	Michigan
Kentucky	Illinois
Ohio	Wisconsin
Indiana	

Region E—Great Plains Multistate Region

Minnesota	Nebraska
Iowa	North Dakota
Missouri	South Dakota
Kansas	

Region F—South Central Multistate Region

Arkansas	Oklahoma
Louisana	New Mexico
Texas	

Region G—Rocky Mountain Multistate Region

Montana	Utah
Idaho	Colorado
Wyoming	

Region H—Pacific Coast Multistate Region

Washington	California
Oregon	Arizona
Nevada	

¶ 32,132 Sales and Transportation by Interstate Pipelines and Distributors

46 F. R. 24585 (May 1, 1981).

18 CFR Parts 157 and 284

[Docket No. RM81-29]

Sales and Transportation by Interstate Pipelines and Distributors

April 27, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: This notice is the second of two rulemakings that the Commission is initiating to reform comprehensively its certificate procedures under section 7(c) of the Natural Gas Act. In the first notice, issued in Docket No. RM81-19, on March 10, 1981 (46 FR 16903, March 16, 1981) the Commission established the framework for such reform and proposed to streamline its certificate procedures for routine activities. This notice proposes to expand the proposed blanket certificate program and to revise the regulations which implement section 311 of the Natural Gas Policy Act of 1978 (NGPA).

Specifically, this notice makes the following proposals: (1) Section 157.210 would permit interstate pipelines to make off-system sales to other interstate pipelines under the blanket certificate program, subject to certain limitations and price determined by an appropriate rate schedule; (2) the end-use restrictions on direct sale gas would be simplified to permit the addition of new process and feedstock loads and the volumetric restrictions would be eliminated; (3) the regulations under section 311(a) of the NGPA would be amended to provide for unlimited successive two year extensions of self-implementing transportation arrangements, subject to Commission review 90 days prior to the effective date of such extension; (4) the regulations under section 311(a)(2) of the NGPA would be amended to authorize intrastate pipelines to transport direct sale gas to an end-user without prior Commission approval, when it is incidental to an interstate pipeline transportation arrangement covered by the blanket certificate; and (5) the blanket certificate program created by Order No. 63 applicable to Hinshaw pipelines would be expanded to apply to local distribution companies.

DATES: Written comments by June 15, 1981. Public hearing on June 5, 1981.

ADDRESS: Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426, Reference Docket No. RM81-29.

FOR FURTHER INFORMATION CONTACT:

Robert Platt, Assistant Advisory Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8457.

Thomas P. Gross, Office of General Counsel, Federal Energy Regulatory Commission 825 North Capitol Street N.E., Washington, D.C. 20426, (202) 357-8171.

This notice presents the second of two rulemakings that the Federal Energy Regulatory Commission (Commission) is initiating to reform comprehensively its certificate procedures under section 7(c) of the Natural Gas Act. In the first notice, issued in Docket No. RM81-19, on March 10, 1981 (46 FR 16903; March 16, 1981) the Commission established the framework for such reform and proposed to streamline its certificate procedures for routine activities. This notice proposes to expand the proposed blanket certificate program to cover certain other categories of transactions that, while not routine, are viewed by the Commission as appropriate for handling by such procedures. This proposal also contains revisions to the regulations which implement section 311 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). The

Commission believes that these amendments will permit it to reduce regulatory burdens and, at the same time, carry out its statutory responsibility to ensure that interstate facilities and transportation arrangements serve the public convenience and necessity.

I. Background

The Commission's jurisdiction over all sales for resale and transportation of natural gas in interstate commerce was originally established in 1942 by amendment of section 7 of the Natural Gas Act (15 U.S.C. 717f). Under the existing section 7 procedures most certificates are issued on a case-by-case basis. The Commission examines the proposed transactions individually to determine whether they are required by the present or future public convenience and necessity. However, some certificates are issued under so-called blanket certificate and "budget-type" certificate programs.[1] These programs permit interstate pipelines that have obtained certificates for the construction and operation of an interstate pipeline system to undertake certain incidental operations without obtaining approval of each specific transaction. These regulations set forth on a generic basis the types of activities and incidental operations which may be authorized by the blanket certificate.

The Commission's opportunity to authorize transactions on a generic basis was considerably extended by the NGPA. Section 311(a) of the NGPA permits the Commission to authorize by rule transportation by interstate pipelines on behalf of intrastate pipelines and local distribution companies and transportation by intrastate pipelines on behalf of interstate pipelines and local distribution companies served by an interstate pipeline.[2]

The notice issued in Docket No. RM81–19 proposes the framework for a comprehensive blanket certificate program for interstate pipelines which not only covers the existing "budget-type" transactions, but also authorizes additional routine transactions which the Commission has found to be generally in the public interest. The framework proposed in that docket provides that a certificate holder is authorized to undertake certain operations and investments without further approval by the Commission. Other operations are authorized under the blanket certificate only if the public is notified of the proposed transaction and no interested party, including the Commission staff, contests it. All other transactions must be authorized through the generally applicable certificate procedures or any other applicable authorization procedure.

The proposals contained in this docket would expand the range of transactions beyond that proposed in Docket No. RM81–19 and amend the section 311(a) regulations contained in Part 284. Specifically, this docket proposes to (1) expand the proposed blanket certificate program to permit off-system sales for resale between interstate pipelines; (2) eliminate certain end-use restrictions presently imposed in the end-user transportation programs under Order Nos. 2 and 27[3] (as certificate program); (3) permit successive extensions of section 311(a) transportation authorizations; (4) permit self-implementing section 311(a)(2) authorizations for intrastate pipelines to

[1] These programs currently include authorizations for: Transportation by interstate pipelines on behalf of any other interstate pipeline (see Subpart G of Part 284); transportation by Hinshaw pipelines on behalf of interstate pipelines (see Subpart G of Part 284); and "buget-type" certificates for the construction and operation of certain facilities which are considered incidental to the pipeline's main facility (see § 157.7, paragraphs (b), (c), (d) and (g)).

[2] Regulations implementing section 311 are contained in Part 284 of the Commission's regulations.

[3] Order No. 2, Docket No. RM75–25 (issued on February 1, 1978), 43 FR 5362 (February 8, 1978), 18 CFR 2.79. Order No. 27, Docket No. RM79–18 (issued April 18, 1979), 44 FR 24825 (April 23, 1979).

transport gas purchased by a qualified end-user; and (5) permit all local distribution companies served by interstate pipelines to obtain the blanket certificate presently availab'e (in § 284.222) to Hinshaw pipelines.[4] The general effect of these proposed changes would be to reduce some of the regulatory obstacles presently encountered by interstate pipelines and local distribution companies served by an interstate pipeline that participates in off-system sales and section 311 transactions.[5]

II. Historical Background

Many of the certification policies the Commission has developed over the last decade, particularly for the type of transactions involved in this rulemaking, have been shaped by the need to prevent the diversion of potential gas supplies from interstate pipelines and to allocate relatively scarce supplies among the highest priority end-users under the Natural Gas Act's regulatory scheme that prevailed from 1954 to 1978. The enactment of the NGPA and the subsequent improvement in the available deliverability of gas supplies now leads us to reassess these policies.

Prior to the enactment of the NGPA, natural gas sold by producers in the interstate market was subject to federal price controls, while much of the gas sold by producers in the intrastate market was sold by producers at unregulated prices. This disparity placed interstate pipelines at a competitive disadvantage in attaching new gas supplies. Eventually, in the 1970's, acute shortages were experienced in the interstate market which forced the pipelines to curtail their sales. The Commission was prompted to impose end-use curtailment plans on the interstate pipelines. Concomitantly, State commissions imposed curtailment plans and limited the attachment of new loads on distributors served from the interstate pipelines.

In response to these shortages, a number of distributors and end-users served by interstate pipelines sought to enhance their own supplies rather than rely solely on purchases from interstate pipelines. Some began to purchase production from wells at locations which would require interstate pipelines to transport the gas to the purchaser. Because direct sales of gas are not subject to Commission jurisdiction, end-users could offer a higher price for such gas than could be paid by interstate pipelines. To prevent potential interstate supplies from being diverted from interstate pipelines, the Commission carefully scrutinized the transportation of such production and would not authorize the transportation if the gas supplies would otherwise have been sold to interstate pipelines. The Commission also carefully examined the price paid for such production to ensure that these purchases would not drive up the unregulated market price for gas.[6]

Since the development of these policies, the availability of interstate supplies and the Commission's regulatory responsibilities have changed significantly. First, the demand for natural gas on many pipelines has dropped below the maximum levels authorized to be served under existing certificates and curtailment plans.

The lower level of demand is a result of a number of factors. A significant number of large industrial users have reduced their consumption of gas either by conservation or by conversion to

[4] A Hinshaw pipeline is an entity engaged in the transportation or sales of natural gas within a state, which is not subject to the jurisdiction of the Commission solely by reason of section 1(c) of the Natural Gas Act.

[5] These transactions have been proposed in this separate docket because they raise more important policy issues than those raised by the transactions proposed in Docket No. RM81-19. However, the Commission will consider these issues and, if possible, incorporate any appropriate amendments at the same time it adopts a final rule in Docket No. RM81-19.

[6] *Natural Gas Pipeline Company of America*, Docket No. CP77-71, 10 FERC ¶ 61,275 (1980); *Transcontinental Gas Pipe Line Co.*, Docket No. CP77-421, issued March 22, 1979; Order No. 533, Docket No. RM79-25, 54 FPC 821, issued August 28, 1975, 40 FR 41760 (Sept. 9, 1975); Order No. 533-A, 54 FPC 2058 (1975).

other more abundant fuels. A portion of the large industrial boiler fuel load which switched to alternative fuels during the earlier periods of heavy curtailment has not returned to using gas. Many distributors acquired their own natural gas supplies to supplement deliveries from interstate pipelines. These "self-help" measures, which included purchasing gas from new sources such as synthetic natural gas plants and local producers, frequently obligated the distributors to commit themselves to pay for some minimum amount under minimum bill and take-or-pay obligations. Such on-going distributor commitments to "self-help" supplies have reduced the proportion of the distributor's requirements served by interstate pipelines. In addition, short-term declines in business activity have significantly reduced demand in some localities. Finally, warmer than normal winters in some parts of the country have reduced temperature-sensitive requirements. These factors result in many distributors' purchasing gas from interstate pipelines in volumes significantly below the maximums authorized under outstanding contracts and certificates.

Second, most interstate pipelines have improved their ability to serve the gas requirements of their customers. The NGPA established a set of maximum lawful prices applicable to both interstate and intrastate markets making it easier for interstate pipelines to compete for and attach new gas supplies. In addition, the NGPA eliminated many of the regulatory obstacles which prevented intrastate supplies from being sold in the interstate market without jurisdictional consequences.[7]

Pipelines sometimes have take-or-pay obligations, or other obligations that require the pipeline to purchase, or at least pay for, more gas than their traditional customers need in the short-term. Unless interstate pipeline can respond to these short-term supply-demand imbalances by making temporary off-system sales, their ability to obtain additional long-term supplies may diminish. A number of pipelines and distributors have proposed that the Commission permit off-system sales to resolve this short term gas supply management dilemma.

Finally, prior to the NGPA the Commission carefully examined on a case-by-case basis prices paid for gas in direct sale arrangements so it could avoid diversion of supplies from interstate pipelines and further escalation of intrastate prices. The imposition of maximum lawful prices by the NGPA eliminates both these concerns and the necessity for the Commission to review these prices on a case-by-case basis.

Given these changes in recent years, the Commission now believes that it is in the public interest to make it administratively easier for interstate pipelines to obtain permission to relieve supply imbalances that may periodically occur by permitting off-system sales between interstate pipelines under the blanket certificate program proposed in Docket No. RM81-19.

Load balancing problems are also being faced at the distributor level. Recently, distributors in many geographical areas have experienced significant short-term declines in demand. If distributors which face take-or-pay obligations from long-standing self-help arrangements (and perhaps minimum bill obligations from their interstate suppliers) cannot arrange for some relief, the resulting rate increases on their systems may drive additional industrial customers to switch to alternative fuels. Several distributors have solved these problems by engaging in off-system sales to end-users under Order No. 30.[8] Order No. 30 permits a

[7] Section 311(b) of the NGPA permits the Commission to authorize sales by intrastate pipelines to interstate pipelines and distributors served by interstate pipelines. Section 312 permits intrastate pipelines to assign surplus gas to interstate pipelines and distributors.

[8] Order No. 30, Docket No. RM79-34, issued May 17, 1979, 44 FR 30323 (May 25, 1979), 18 CFR Part 284, Subpart F.

distributor to sell volumes attributable to its local supplies to end-users for the purpose of displacing fuel oil. However, Order No. 30 is scheduled to expire on May 31, 1981.

Other distributors which hold exemptions under section 1(c) of the Natural Gas Act (so-called Hinshaw pipelines), have sold local production by obtaining blanket certificates under Order No. 63.[9] Order No. 63 promulgated the regulations at § 284.222 to permit Hinshaw pipelines to sell volumes attributable to local supplies to interstate pipelines and other distributors served by interstate pipelines. This "local supply" test imposed in both Order No. 63 and Order No. 30, limits the total volumes which may be sold, thus minimizing the possibility that the selling distributor would merely broker its pipeline purchases. Some have argued that if distributors were permitted to resell their pipeline entitlements off-system, then the pipeline supplier would face unpredictable demand requirements which would hinder the pipeline's supply management efforts. Although the Commission is aware of certain proposals to permit distributors to sell pipeline supplies as well as local supplies [10] we do not propose to include such sales as a part of this certificate reform program.[11] Instead, the proposed rule would extend eligibility for obtaining Order No. 63 certificates to all distributors served by interstate pipelines.

In summary, while other amendments are proposed in this notice, the main thrust of this proposal is to permit two new categories of off-system sales. First, sales will be permitted between interstate pipelines under the blanket certificate proposed in Docket No. RM81–19. Second, the sale of local supplies previously permitted for Hinshaw pipelines will be expanded to permit any distributor served by an interstate pipeline to make such sales.

III. Authorized Transactions

A. Sales for Resale by Interstate Pipelines

As discussed above the Commission is proposing in § 157.210 to permit interstate pipelines to make off-system sales to other interstate pipelines under the blanket certificate program. Briefly stated, the blanket certificate will authorize sales for resale in which the purchaser is an interstate pipeline and receives the gas for its system supply. However, the sales are subject to certain conditions, such as a one year limitation, maximum daily deliveries of 100,000 MMBtu equivalent of gas, special reporting requirements, maximum rates and charges, and the notice and protest procedure proposed in Docket No. RM81–19. The latter requirement will prevent any such sale from being authorized under the blanket certificate if after public notice any interested person or staff contests the transaction. These sales are also subject to interruption to the extent required to provide adequate service to the selling pipeline's customers at the time of the sale.

One of the more important issues that must be resolved in permitting these sales is the appropriate sale price. In considering the sale price, the Commission must balance competing considerations. If the price of the off-system sale is so low that the selling interstate pipeline cannot recover its cost of purchasing the gas, then its on-system customers would carry the costs not recovered through the price of the off-system sale. On the other hand, if the

[9] Order No. 63, Docket No. RM79–24, issued Jan. 3, 1980, 45 FR 1872, (Jan. 9, 1980). 18 CFR 284.222.

[10] Transcript, Subcommittee on the Review of the Decisional Process of the Advisory Committee on Practice and Procedure (December 4, 1980).

[11] Historically, each interstate pipeline has borne the responsibility for managing its long-term supply acquisition program to meet the needs of its system. The proposed rule does not alter this role, but rather establishes criteria for off-system sales which are consistent with this interstate pipeline function. By limiting distributor sales to local supplies, this rule affords distributors flexibility in managing their short-term imbalances in self-help supplies without disrupting the interstate pipeline's predominant role.

price is excessive, it may violate the statutory requirement that jurisdictional rates be "just and reasonable."

As currently proposed, the price for these sales would be established by a rate schedule which the Commission determines is appropriate for these sales. Once a rate schedule has been approved as appropriate, the certificate holder may use that schedule for subsequent sales.

The proposed rule will afford pipelines some latitude in formulating an appropriate sales rate schedule. However, the proposal requires that the rate schedule provide for a commodity charge and be designed so as to permit the selling pipeline to recover its average purchased gas costs and any transportation costs associated with the delivery of the gas.[12] The Commision seeks comments regarding whether such a price is adequate to protect the existing customers of the selling pipeline and to assure that the benefit of the sale outweigh the costs.

The Commission believes that the economic benefits of off-system sales should be distributed to the customers of the selling interstate pipeline. Because these sales for resale will be authorized under the blanket certificate proposed in Docket No. RM81-19, the revenue crediting provision in § 157.206(g) proposed in that docket will apply to any sale for resale authorized under § 157.210. This rule includes conforming changes to proposed § 157.206(g).

Finally, proposed § 157.210(a)(5) prohibits the sale of gas acquired by the certificate holder solely or primarily for the purpose of making a sale under this section. Sales under proposed § 157.210 are intended to permit the selling pipeline to alleviate problems posed by excess deliverability or take-or-pay commitments. If a series of pipelines were to sell repeatedly the same gas under the blanket certificate, such a series of sales would create undesirable rate consequences to the customers of participating pipelines. Therefore, the restriction of § 157.210(a)(5) is included to avoid such series of sales.

This proposed rulemaking is predicated on the view that the public interest would be served by making it generally easier for pipelines to make off-system sales subject to generic qualifications rather than requiring a case-by-case review of each potential transaction. The Commission is aware of a contrary view. Some believe that the potential damages to the public interest from off-system sales are such that a case-by-case review is required. Those holding this view argue that there is a need to examine the price to ensure that existing customers are not damaged by pipelines' buying "high" and selling "low". They also argue that in an environment with partial deregulation of wellhead prices, pipelines may buy deregulated gas at prices that are above prices for alternative fuels, yet still market this gas by rolling it in with the cost of cheaper regulated gas. Interstate pipelines with substantial cushions of old gas, it is argued, would have a competitive advantage in competing for new gas supplies. If such pipelines can easily sell this gas off-system, the result may be to destabilize the market for new gas supplies or make it difficult for some pipelines to obtain new gas supplies because available supplies are tied up by pipelines with large old-gas cushions.

[12] As the Commission explained in *Trunkline Gas Company*, Docket No. CP80-550 (issued February 20, 1981), in which it issued a certificate authorizing off-system sales, the Commission has adopted the policy that the sales price for such sales should permit the selling pipeline to recover its costs. The Commission also noted that fixed price contracts which do not reflect the monthly increases in purchased gas costs generally impose an unacceptable subsidy upon the selling pipeline's existing customers.

In other cases, where the average cost of gas was less than the ceiling price applicable to producer sales under section 102 of the NGPA, we have permitted the section 102 price to be charged as representative of the replacement cost of the gas sold. See *Natural Gas Pipeline Co. of America*, Docket Nos. CP80-502 and CP80-520, issued January 27, 1981; *Cities Service Gas Co.*, Docket No. CP80-499, issued December 22, 1980.

The Commission believes that these concerns to the extent that they are pertinent can be raised under the notice procedures in individual cases. However, the Commission invites comment on the need for case-by-case analysis.

B. Transportation to End-Users

The Commission believes that the original policy considerations which gave rise to the end-use volumetric limitations upon the transportation of gas sold at the wellhead directly to end-users no longer justify previously imposed restrictions. Accordingly, the Commission is proposing to unify and eliminate volumetric and end-use restrictions governing such transportation covered by its blanket certificate program.

Historically, the Commission has taken a conservative approach in permitting the transportation of gas sold at the wellhead directly to end-users (hereinafter referred to as "direct sale gas"). This approach reflected its concern that such sales could divert significant volumes of natural gas from interstate pipeline system supplies because the sales were not subject to the Commission's price regulations under the Natural Gas Act. As a result, the Commission imposed stringent end-use and volumetric limitations on certificates authorizing the transportation of gas sold directly by the producer to the end-user. Pursuant to Order Nos. 533 and 2,[13] interstate pipelines may transport gas only for end-users who purchase the gas for high-priority requirements, such as process and feedstock uses. Pursuant to Order No. 2, end-users are not permitted to increase their requirments because the volume transported was limited to the end-user's base period curtailment entitlements for such high priority end uses. In addition, the Commission expected participating end-users to demonstrate progress toward conversion to alternative fuels when seeking to renew transportation certificates.

After the enactment of the NGPA and the Public Utilities Regulatory Policies Act (PURPA), the Commission created a separate direct sale program for schools, hospitals and essential agricultural users in Order No. 27. That order does not impose the end-use and volumetric restrictions that applied to process and feedstock users in the Order No. 2 program. Instead, schools, hospitals and essential agricultural users may serve newly added high priority loads with direct sale gas, and did not have to demonstrate progress toward converting to alternative fuels. The Commission has never afforded process and feedstock users the same treatment as the schools, hospitals and essential agricultural users under Order No. 27.[14]

The Commission's blanket certificate program, proposed in Docket No. RM81-19 would eliminate the need for each transporting pipeline to file a separate application under section 7(c) of the Natural Gas Act for transportation to individual end-users. The blanket certificate would authorize transportation to "qualified end-users" (which is defined as including the end-users eligible under the Order No. 2 and Order No. 27 programs). If the transportation is for a term of 5 years or less, then the transaction may go forward without further Commission approval. If the transportation is for a term greater than 5 years, then the transporting interstate pipeline must file a request under the blanket certificate's notice procedure. As proposed in Docket No. RM81-19, transportation for end-users would be subject to the end-use restrictions and volumetric limitations applicable to Order No. 2 or Order No. 27 certificates. (See, proposed

[13] Order No. 533, Docket No. RM 75-25, (issued August 28, 1975), 40 FR 41760 (Sept. 9, 1975). Order No. 2, *supra*.

[14] Order No. 52, Docket No. RM80-1, issued October 5, 1979, 44 FR 60080 (October 18, 1979), liberalized some of the end-use restrictions imposed by Order No. 2, but not to the extent as Order No. 27.

§ 157.209(d)(3) and (4) in Docket No. RM81–19).

In this docket the Commission proposes to eliminate the volumetric restriction and simplify all end-use requirements in a manner consistent with the Order No. 27 requirements. This would permit new process and feedstock loads which were not reflected in a curtailment base period to be served by direct sale gas just as new essential agricultural loads may now be served under Order No. 27. The only end-use restriction which would be retained is the restriction that direct sale gas be consumed in qualified end-uses.

With respect to the volumetric restrictions, the proposed rule will permit the end-user to attach new loads to be served by direct sale gas. Any new loads which the end-user attaches in this manner are outside the scope of an interstate pipeline curtailment plan, and the end-user should be aware that any future service from system supplies to these loads is not assured. Because new load attachments will not adversely affect the interstate pipeline's other customers, the volumetric restrictions imposed in Order No. 2 do not appear to be necessary in this program. Although this change in volumetric restrictions may provide an opportunity for new high-priority load growth by some customers of interstate pipelines, the Commission believes that this approach toward the transportation of direct sale gas is consistent with the legislative intent of section 608 of PURPA.

C. Successive Transportation Arrangements Under Section 311

Section 311(a)(1) of the NGPA permits the Commission to authorize interstate pipelines to transport natural gas on behalf of intrastate pipelines or local distribution companies. Section 311(a)(2) permits the Commission to authorize intrastate pipelines to transport gas on behalf of interstate pipelines and local distribution companies served by any interstate pipeline. In Order No. 46,[15] the Commission promulgated rules under section 311(a) to authorize such transportation by both interstate and intrastate pipelines without prior Commission approval, if, among other requirements, the transported natural gas enters the system supplies of a pipeline or distributor. Although section 311(a) does not impose a statutory time limit on the duration of such transactions, the Commission exercised its discretion to limit self-implementing section 311(a) transportation arrangements to a term of 2 years or less. Order No. 46 provided for a single two year extension of any self-implementing section 311(a) transportation arrangement. Under §§ 284.105 and 284.125, the transporting pipeline must file a request for an extension at least 90 days before the expiration of its initial authorization. If the Commission does not act during this period, the authorization is automatically extended for up to two years. Transportation arrangements for terms longer than four years are subject to the procedures for prior approval established in §§ 284.107 and 284.127.

If a pipeline proposes to charge a higher rate during the extension, the new rate is subject to the criteria and approval procedure in §§ 284.103 and 284.123. However, even if the pipeline proposes to continue to charge the same rate that it used during the previous term of the transaction, the Commission will nonetheless review the propriety of the rate during the 90 day period and may exercise its authority under section 311(c) of the NGPA to impose a condition specifying a rate lower than that proposed by the pipeline.

The Commission proposes to amend §§ 284.105 and 284.125 of its section 311(a) regulations to permit unlimited successive two-year extensions of self-implementing transportation arrangements. Because such an extension is subject to Commission review for 90 days prior to its effective

[15] Order No. 46, Docket No. RM79–75 (issued August 30, 1979), 44 FR 52179 (September 7, 1979).

date, successive extensions will be monitored to protect the public interest.

D. Transportation of Direct Sale Gas Under Section 311

As previously discussed, Order Nos. 2 and 27 (as well as the proposed blanket certificate program) authorize certain transportation of direct sale gas to end-users. Frequently the selling producer's well is located near an intrastate pipeline, and the intrastate pipeline needs section 311(a)(2) authorization to permit it to transport the gas to the interstate pipeline without becoming subject to Natural Gas Act jurisdiction.

The Commission proposes to follow its practice in Order No. 30 by authorizing intrastate pipeline transportation which is incidental to the interstate pipeline's transportation of direct sale gas. The regulations would permit the intrastate pipeline to enter into contractual agreements to transport the direct sale gas "on behalf of" the interstate pipeline.[16] The intrastate pipeline could collect a fair and equitable transportation charge either directly from the end-user, or indirectly from the interstate pipeline as an intermediary.

Because the direct sale gas is delivered to an end-user and is not for system supplies, transportation of the gas would not otherwise qualify for a self-implementing section 311(a)(2) authorization under § 284.122(a). Accordingly, the Commission proposes to amend § 284.122(b) to create an exception to the system supply test so as to permit such incidental intrastate transportation to commence without prior Commission approval.

E. Blanket Certificates for Local Distribution Companies

The Commission has established a blanket certificate program which permits Hinshaw pipelines to transport, sell, and assign natural gas to the same extent that an intrastate pipeline is permitted to engage in such transactions under section 311 or 312 of the NGPA.[17] Under a blanket certificate granted pursuant to Order No. 63, Hinshaw pipelines may transport, assign and sell natural gas in interstate commerce for resale without jeopardizing their exempt status under section 1(c) of the Natural Gas Act. These blanket certificates permit Hinshaw pipelines to make their excess supplies available to the interstate market. The blanket certificates further permit the Hinshaw pipeline to use its transportation facilities to transport gas and thereby eliminate the need for interstate pipelines to build duplicate facilities or use less direct transportation routes.

The Commission believes that the policies underlying the blanket certificate program for Hinshaw pipelines apply equally to local distribution companies and would benefit gas consumers. We propose to amend § 284.222 so that any local distribution company which is served by an interstate pipeline and holds a blanket certificate may transport natural gas on behalf of an interstate pipeline or a local distribution company served by interstate pipelines, subject to the terms and conditions of Subpart C of Part 284. The certificate holder may sell volumes attributable to local supplies, subject to the terms and conditions of Subpart D of Part 284.[18] In addition, the certificate holder may assign its right to purchase gas in a first sale to an interstate pipeline or distributor, subject to the terms and conditions of Subpart E of Part 284. Other than expanding the eligibility for holding an Order No. 63 blanket certificate, and clarifying application requirements, no substantive amendments are proposed to the regulations governing these blanket certificates.

[16] As was noted in Order No. 46, the "on behalf of" test may be satisfied by a contractual provision establishing an agency relationship. The test does not require an interstate pipeline to take title to the gas.

[17] Order No. 63, Docket No. RM79-24, issued January 3, 1980, 45 FR 1872 (January 9, 1980).

[18] At present, distributors' sales outside their service areas are limited to the sale of local supplies under the Commission's Order No. 30 program.

Some persons may view the proposed expansion of Order No. 63 as providing a distributor the opportunity to sell surplus gas which should otherwise be eliminated by reducing the distributor's purchased gas from a supplying interstate pipeline. These persons would argue that interstate pipeline curtailment plans are the only appropriate means for allocating surplus supplies created by the self-help efforts of distributors. The Commission invites comments on this question, and especially seeks comments based upon the experience gained from distributor sales under order No. 30.

IV. Summary of Proposed Rule

In order to authorize sales for resale between interstate pipelines, the Commission is proposing to add a new § 157.210 to the blanket certificate program proposed in Docket No. RM81–19. The sales would be subject to certain conditions and a rate schedule which the Commission determines is appropriate for the sale.

The proposed rule also eliminates certain end-use restrictions presently imposed by Order Nos. 2 and 27 in the end-user transportation programs and reflected in the blanket certificate proposal in Docket No. RM81–19. The Commission believes this change will place process and feedstock end-users on a parity with other high-priority users.

The proposed rule would also expedite interstate and intrastate pipeline transportation under section 311(a) of the NGPA by amending the existing regulations to provide for successive extensions of self-implementing transportation authorization.

The blanket certificate program proposed in Docket No. RM81–19 provided for interstate pipeline transportation of direct sale gas to qualified end-users, but did not provide for intrastate pipeline transportation of such gas. The proposed rule would authorize such intrastate pipeline transportation on a self-implementing basis under section 311(a)(2) of the NGPA.

Finally, the proposed rule would amend § 284.222, which establishes the blanket certificate program for Hinshaw pipelines, to permit any local distribution company served by an interstate pipeline to hold such a certificate. The filing requirements for a blanket certificate are also clarified by amendments to § 284.222(c)(7).

V. Environmental Issues

An environmental assessment of the proposed rulemaking is being prepared by the Commission's environmental staff in conjunction with Docket No. RM81–19. This assessment will identify and include the significance of any potential environmental impact which might result from transactions which would be authorized under this proposed rule. The environmental assessment will provide the basis for determining the need to prepare an environmental impact statement (EIS) prior to the issuance of the final rule.

Sales for resale authorized by § 157.210 of this proposed rule will be subject to the environmental conditions proposed in Docket No. RM81–19. Full consideration will be given to these environmental conditions as well as the nature of all transactions proposed in this docket when preparing the environmental assessment.

Any person who wishes to submit comments on environmental issues should provide a detailed explanation which addresses each specific environmental concern and the reason each concern is felt to be a significant issue. This information will be helpful to the staff in developing an environmental record in this rulemaking, and will be incorporated in the Commission's scoping process should an EIS be prepared.

VI. Certification of No Significant Economic Impact on Small Businesses

The Regulatory Flexibility Act (RFA) [19] requires certain statements,

[19] 5 U.S.C. 601–612 (Pub. L. 96–354, September 19, 1980).

descriptions and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities."

Pursuant to section 605(a) of the RFA, the Commission finds that the provisions of the Act do not apply to this rulemaking. If promulgated, this rulemaking, among other things, would simplify procedures under which interstate pipelines may obtain certain certificates. The budget-type certificate regulations were promulgated initially for similar purposes 24 years ago. The characteristics of the participants in the budget-type certificate program reflect the nature of the interstate pipeline industry. With five exceptions, only Class A pipeline companies [30] have participated in the program. Of the five exceptions, only two were not affiliated with a major natural gas company. Because the nature of the budget-type certificate program and the proposed blanket certificate program are similar, the nature of the participants in each program should also be similar. Therefore, the Commission believes that very few, if any, of the interstate pipelines which will participate in this program will be small entities.

The proposed rule also provides local distribution companies served by interstate pipelines with the opportunity to obtain blanket certificates. Local distribution companies engage in the distribution and retail sale of gas within service areas over which they possess exclusive control or franchises. As a result of their exclusive right to sell gas in their service area, each is "dominant in its field of operation" and thus does not qualify as a "a small business concern" under section 3 of the Small Business Act, 15 U.S.C. 632. Moreover, the Small Business Administration regulations do not identify any local distribution companies as small. (See 13 CFR Part 121.) Because the section 3 definition of "small business concern" is incorporated by reference into the definition of "small entity" in the RFA, our proposal to expand the blanket certificate program set forth in § 284.222, does not affect "small entities" within the meaning of Section 601(6) of the RFA and therefore does not require a regulatory flexibility analysis.

As such, this rulemaking does not impose any regulatory or administrative burdens upon a significant number of small entities, nor does it require an expenditure of resources by such entities. For these reasons, the Commission hereby certifies that this rulemaking, if promulgated, would not have a significant impact on a substantial number of small entities.

VII. Public Comment Procedure

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM81-29. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, June 15, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. during regular business hours.

B. *Public Hearing.* A public hearing on this proposed rule will be held on June 5, 1981 beginning at 10:00 a.m. EDT at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The exact location will be posted at the

[30] To be classified as a Class A company, the company should have annual gas operating revenues of $2,500,000 or more and maintain that level for three consecutive years. (See Part 201, Uniform System of Accounts for Natural Gas Companies Subject to the Provisions of the Natural Gas Act (Class A and Class B); General Instructions.)

Commission on the morning of the hearing. Interested persons may also obtain this information by calling the Office of the Secretary of the Commission.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, DC 20426, no later than seven days prior to the hearing. Requests should reference Docket No. RM81–29, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Division of Public Information three days before the hearing and will be available at the site of the hearing on the morning it is convened.

The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available in the public file for this proceeding, Docket No. RM81–29 in the Commission's Division of Public Information.

(Natural Gas Act, (15 U.S.C. 717); Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, (15 U.S.C. 3301); Public Utilities Regulatory Policies Act of 1978 section 608, Pub. L. 95–617, 92 Stat. 3173, (15 U.S.C. 717f))

Accordingly, the Commission proposes to amend the regulations in Parts 157 and 284, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

§§ 157.203 and 157.205 [Amended]

1. Proposed §§ 157.203(c) and 157.205(a) are amended by inserting "157.210" between "157.209(b)" and "157.211(b)."

2. Proposed § 157.206 is amended by revising paragraph (g)(1) to read as follows:

§ 157.206 Standard conditions.

* * * * *

(g) *Treatment of revenues.* (1) Except as provided in subparagraphs (2) and (3) of this paragraph, all revenues received for sales for resale in excess of purchased gas costs, or for transportation (including storage service) authorized under the blanket certificate in excess of an allowance of one cent per MMBtu shall be credited to Account No. 191 and flowed back to the certificate holder's customers.

* * * * *

§ 157.209 Transportation. [Amended]

3. Proposed § 157.209 is amended in paragraph (d)(3) by removing the phrase "§ 2.79 of this chapter or".

4. Proposed § 157.209 is amended by revising paragraph (d)(4) to read as follows:

* * * * *

(d) *Special conditions.* * * *

(4) Any transportation authorized under paragraphs (a) or (b)(1) of this section is conditioned upon the natural gas being consumed only by a qualified end-user for qualified end-uses.

* * * * *

5. Proposed Subpart F of Part 157 is amended by adding a new § 157.210 is proposed to read as follows:

§ 157.210 Sales for resale.

(a) *Prior notice.* Subject to the notice procedure of § 157.205, the certificate holder is authorized to sell natural gas in interstate commerce for resale, if:

(1) The buyer is an interstate pipeline acquiring the gas for its system supplies,

(2) The sale does not exceed a period of one year,

(3) The volume sold does not exceed 100,000 MMbtu per day,

(4) The sale is made under a commodity charge, which reflects both the cost of purchased gas and transportation costs, as contained in an appropriate currently effective sales rate schedule on file with the Commission,

(5) The sale does not involve the sale of any natural gas acquired by the certificate holder solely or primarily for the purpose of making a sale under this section,

(6) The buyer is not an interstate pipeline supplier of the seller during the duration of the sale, and

(7) The sale shall be subject to interruption by the certificate holder to the extent that natural gas subject to the sale is required to provide adequate service to the certificate holder's other customers at the time of the sale.

(b) *Contents of request.* Requests filed pursuant to this section shall contain:

(1) The identity of the seller and buyer;

(2) The dates of commencement and anticipated termination of the sale;

(3) The estimated total and daily quantities (in MMBtu's) of natural gas to be sold in this transaction;

(4) The rate to be charged and the applicable rate schedules;

(5) The affidavit that service pursuant to the sale is subject to interruption to the extent that natural gas subject to the sale under this section is required to enable the certificate holder to provide adequate service to its customers; and

(6) The total quantity of gas being sold in transactions authorized by this section at the time that the request is filed.

PART 284—CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

6. Section 284.105 is amended by revising paragraph (a) to read as follows:

§ 284.105 Extensions.

(a) *General Rule.* An interstate pipeline seeking to extend a transporation arrangement initially authorized under § 284.102(a), including those subsequently extended under this section, shall file an extension report as required in § 284.106(c).

* * * * *

7. Section 284.122 is amended by revising paragraph (b)(1) to read as follows:

§ 284.122 Transportation by intrastate pipelines.

* * * * *

(b) *Limitations.* (1) Authorization under paragraph (a) of this section is limited to an arrangement:

(i)(A) Which does not exceed a period of two years, and

(B) In which the transported natural gas is delivered directly or indirectly to an interstate pipeline, intrastate pipeline, or local distribution company, which receives such natural gas for its system supply for resale, or

(ii) In which natural gas is purchased by a qualified end-user and is also transported by an interstate pipeline pursuant to a blanket certificate issued under Subpart F of Part 157 of this chapter.

* * * * *

8. Section 284.125 is amended by revising paragraphs (a) and (b) to read as follows:

§ 284.125 Extensions.

(a) *General rule.* An intrastate pipeline seeking to extend a transportation arrangement initially authorized under § 284.122(a), including those subsequently extended under this

section, shall file an extension report as required in § 284.126(c).

(b) *Approval.* (1) If an extension report as required in § 284.126(c) is duly filed, the proposed extension may take effect unless the Commission, prior to the beginning of the proposed extension, and after opportunity for written comments, determines, by order, that the proposed extension is not authorized. If the intrastate pipeline proposes to charge a rate during the extension which is different than the rate previously charged, the new rate is subject to the requirements and approval procedures of § 284.123.

(2) If the Commission determines, by order, that the proposed extension shall be modified, the extension may take effect only as modified.

* * * * *

9. Section 284.222 is revised to read as follows:

§ 284.222 Certain transportation, sales and assignments by local distribution companies.

(a) *Applicability.* This section applies to local distribution companies served by interstate pipelines including persons who are not subject to the jurisdiction of the Commission, by reason of section 1(c) of the Natural Gas Act.

(b) *Blanket certification.* Any local distribution company served by a interstate pipeline or any Hinshaw pipeline may apply for a blanket certificate under this section. Upon application therefore, the Commission will conduct a hearing pursuant to section 7(c) of the Natural Gas Act and §§ 1.32 and 157.11 of this chapter and, if required by the present or future public convenience and necessity, the Commission will issue a blanket certificate to such a local distribution company. Such certificate will authorize the certificate holder to engage in the sale, transportation, or assignment of natural gas, that is subject to the Commission's jurisdiction under the Natural Gas Act, to the same extent and in the same manner that intrastate pipelines are authorized to engage in such activities by Subparts C, D, and E and § 284.203 of this Part (as amended from time to time), except as otherwise provided in paragraph (e)(2) of this section.

(c) *Application procedure.* Applications for blanket certificates shall state:

(1) The exact legal name of applicant; its principal place of business; whether an individual, partnership, corporation or otherwise; state under the laws of which organized or authorized; the agency having jurisdiction over rates and tariffs and the name, title, and mailing address of the person or persons to whom communications concerning the application are to be addressed,

(2) The volumes of natural gas which:

(i) Were received during the most recent 12-month period by the applicant within or at the boundary of a state, and

(ii) Were exempt from the Natural Gas Act jurisdiction of the Commission by reason of section 1(c) of the Natural Gas Act, if any,

(3) The total volume of natural gas received by the applicant from all sources during the same time period,

(4) Citation to all currently valid declarations of exemption issued by the Commission under section 1(c) of the Natural Gas Act,

(5) A statement that the applicant will comply with the conditions in paragraph (e) of this section,

(6) A form of notice suitable for publication in the **Federal Register**, as contemplated by § 157.9 of this chapter, which will briefly summarize the facts contained in the application in such a way as to acquaint the public with its scope and purpose, and

(7) A statement of the methodology to be used in calculating rates for services to be rendered, setting forth any elections under § 284.123 or paragraph (e)(2) of this section and a sample calculation employing the methodology using current data. If a rate election is made under paragraph (e)(2), this statement shall contain the following items (reflecting the 12-month period used to justify costs in the most recently approved rate case conducted by an appropriate state regulatory agency):

(i) Total operating revenues,

(ii) Purchase gas costs,

(iii) Distribution costs (which include that portion of the common costs allocated to the distribution function),

(iv) The volume throughput of the system categorized by sales, transportation and exchange service, and

(v) A study which determines transportation costs on a unit revenue basis in accordance with paragraph (e)(2) of this section, including any supporting work papers.

(d) *Effect of certificate.* (1) A certificate issued pursuant to this section will authorize the certificate holder to engage in transactions of the type authorized by Subparts C, D and E and § 284.203 of this Part.

(2) Acceptance of a certificate or conduct of an activity authorized thereunder will:

(i) Not impair the continued validity of any exclusion under section 1(c) of the Natural Gas Act which may be applicable to the certificate holder, and

(ii) Not subject to the certificate holder to the Natural Gas Act jurisdiction of the Commission except to the extent necessary to enforce the terms and conditions of the certificate.

(e) *General conditions.* (1) Except as provided in paragraph (e)(2) of this section, any transaction authorized under a blanket certificate shall be subject to the same rates and charges, terms and conditions and reporting requirements that would apply if the transactions were authorized for an intrastate pipeline by Subparts C, D and E and § 284.203 of this Part (as amended from time to time).

(2) *Rate election.* If the certificate holder does not have any existing rates on file with the appropriate state regulatory agency for city-gate service, the certificate holder may make the rate election specified in § 284.123(b)(1) only if:

(i) The certificate holder's existing rates are approved by an appropriate state regulatory agency,

(ii) The rates and charges for any transportation are computed by using the portion of the certificate holder weighted average annual unit revenue (per MMBtu) generated by existing rates which is attributable to the cost of gathering, treatment, processing, transportation, delivery or similar service (including storage service), and

(iii) The Commission has approved the method for computing rates and charges specified in paragraph (e)(2)(ii) of this section.

(3) *Incremental pricing.* Prior to engaging in any sale or assignment under the blanket certificate to a buyer subject to the incremental pricing provisions of Title II of the NGPA and Part 282 of this chapter, the selling pipeline shall receive an undertaking from the buyer to price incrementally the gas sold to the same extent required for transactions authorized under section 311(b) or 312 of the NGPA.

(4) *Volumetric test.* The volumes of natural gas sold or assigned under the blanket certificate may not exceed the volumes obtained from sources other than interstate supplies.

(5) *Filings.* Any filings made with the Commission that report individual transactions shall reference the docket number of the proceeding in which the blanket certificate was granted.

(6) *Tariff filings.* (i) The tariff filing requirements of Part 154 of this chapter shall not apply to transactions authorized by the blanket certificate.

(ii) The certificate holder shall file with the Commission a copy of all contracts applicable to a transaction authorized by the blanket certificate as a part of the initial full report required by §§ 284.126 and 284.148. The certificate holder shall also file with the Commission each amendment to such contracts, within 30 days of the execution of the amendment.

(f) *Pregrant of abandonment.* Abandonment of transportation services or sales, pursuant to section 7(b) of the Natural Gas Act, is authorized upon the expiration of the contractual term of each individual arrangement authorized by a blanket certificate under this section.

(g) *Hinshaw pipelines without blanket certificate.* A Hinshaw pipeline which does not obtain a blanket certificate under this section is not authorized to sell, assign or transport natural gas as an intrastate pipeline by Subparts C, D, E and F of Part 284 of this chapter.

(h) *Definitions.* For the purposes of this section:

(1) A "Hinshaw pipeline" means any person engaged in the transportation of natural gas which is not subject to the jurisdiction of the Commission under the Natural Gas Act by reason of section 1(c) of the Natural Gas Act.

(2) "Interstate supplies" means any natural gas obtained, either directly or indirectly, from:

(i) The system supplies of an interstate pipeline, or

(ii) Natural gas reserves which were committed or dedicated to interstate commerce on November 8, 1978.

(3) A "certificate holder" means any Hinshaw pipeline or local distribution company served by an interstate pipeline with an effective blanket certificate issued pursuant to this section.

¶ 32,133 High-Cost Gas Produced From Tight Formations (Colorado-14)

46 F. R. 25643 (May 8, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado—14)]

High-Cost Gas Produced From Tight Formations; Colorado

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado Oil and Gas Conservation Commission that the Dakota Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on June 3, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on May 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

Issued: May 4, 1981.

I. Background

On April 23, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Dakota Formation located in Mesa and Garfield Counties, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Dakota Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies certain lands in Mesa and Garfield Counties, Colorado. The area is approximately six to eight miles northeast of the city of Grand Junction, Colorado, and surrounds the town of DeBeque. The area is bordered by the Book Cliffs outcrop of the Mesaverde formation to the southwest and is traversed by the Colorado River. The recommended area contains 334,995 acres and consists of all or portions of Townships 7 through 11 South, Ranges 96 through 100 West, 6th P.M. Approximately 78 percent of this land is federal acreage and 22 percent is fee. The average depth to the top of the Dakota Formation is 7075 feet. The formation ranges from 160 to 275 feet in thickness.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–19 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Dakota Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before June 3, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado—14), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE, Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than May 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (48) to read as folllows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(25) through (47) [Reserved]

(48) *Dakota Formation in Colorado* RM79-76 (Colorado—14)

(i) *Delineation of formation.* The Dakota Formation is found in Mesa and Garfield Counties, Colorado, and consists of all or portions of Townships 7 through 11 South, Ranges 96 through 100 West, 6th P.M.

(ii) *Depth.* The Dakota Formation occurs at an average measured depth of 7075 feet.

¶ 32,134 High-Cost Gas Produced From Tight Formations (Colorado-15)

46 F. R. 25644 (May 8, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado—15)]

High-Cost Gas Produced From Tight Formations; Colorado

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado Oil and Gas Conservation Commission that the Dakota formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on June 3, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on May 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

Issued May 4, 1981.

I. Background

On April 23, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Dakota formation located in Garfield and Rio Blanco Counties, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Dakota Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies portions of Garfield and Rio Blanco Counties, Colorado. The recommended area is located in the Dougla Creek Arch area approximately 50 to 70 miles northwest of the city of Grand Junction. The area contains approximately 264,538 acres, consisting of all or portions of Townships 3 through 8 South, Ranges 98 through 103 West, 6th P.M. Approximately 85 percent of this land is federal acreage and 15 percent is fee. The depth to the top of the Dakota Formation ranges from 5,480 to 9,225 feet and averages 6,993 feet. The thickness of the formation ranges from 100 to 200 feet.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–15 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Dakota Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before June 3, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado—15), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than May 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (50) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(25) through (49) [Reserved]

(50) *Dakota Formation in Colorado* RM79–76 (Colorado—15).

(i) *Delineation of formation.* The Dakota Formation is found in Garfield and Rio Blanco Counties, Colorado, and consists of all or portions of Townships 3 through 8 South, Ranges 98 through 103 West, 6th P.M.

(ii) *Depth.* The depth to the top of the Dakota Formation ranges from 5,480 to 9,225 feet and averages 6,993 feet.

¶ 32,135 High-Cost Gas Produced From Tight Formations (Mississippi-2)

46 F. R. 27963 (May 22, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Mississippi-2)]

High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the State Oil and Gas Board of Mississippi that the Rea sand of the Mississippian Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on June 17, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on June 2, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307 or Walter W. Lawson, (202) 357-8703.

Issued: May 18, 1981.

I. Background

On March 30, 1981, the State Oil and Gas Board of Mississippi (Mississippi) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Rea Sand of the Mississippian Formation in Clay County, Mississippi, be designated as a tight formation. Pursuant to § 371.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Mississippi's recommendation that the Rea Sand of the Mississippian Formation be designated a tight formation should be adopted. Mississippi's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of the Recommendation

Mississippi recommends that the Rea Sand of the Mississippian Formation found in portions of Township 16 South, Range 5 East; Township 17 South, Range 5 East; Township 16 South, Range 6 East; and Township 17 South, Range 6 East, Clay County, Mississippi, be designated as a tight formation.

The recommended formation varies in thickness from 30 feet to 160 feet and occurs at depths ranging from 8,865 feet to 9,975 feet. The only producing well in the Rea Sand of the Mississippian Formation in the recommended area is completed in an interval of 9,058 feet to 9,100 feet.

III. Discussion of Recommendation

Mississippi claims in its submission that evidence gathered and presented at a public hearing in support of this recommendation domonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stablized production rate, against atmospheric pressure, of wells

completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Mississippi further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Mississippi that the Rea Sand of the Misissippian Formation, as described and delineated in Mississippi's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before June 17, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Mississippi-2), and should give reasons including supporting data for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than June 2, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Mississippi's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(49) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(25) through (48) [Reserved]

(49) *The Rea Sand of the Mississippian Formation in Mississippi.* (Mississippi-2).

(i) *Delineation of Formation.* The Rea Sand of the Mississippian Formation is found in portions of Township 16 South, Range 5 East; Township 17 South, Range 5 East; Township 16 South, Range 6 East;

and Township 17 South, Range 6 East, in Clay County, Mississippi.

(ii) *Depth.* The recommended formation occurs at depths ranging from 8,865 feet to 9,975 feet and varies in thickness from 30 feet to 160 feet.

¶ 32,136 High-Cost Gas Produced From Tight Formations (Texas-10)

46 F. R. 27964 (May 22, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas-10)]

High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Railroad Commission of Texas that the Edwards Limestone Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on June 17, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written request for a public hearing are due on June 2, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307 or Walter Lawson, (202) 357-8556.

Issued: May 18, 1981.

I. Background

On March 30, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Edwards Limestone Formation in Dewitt, Karnes, and Lavaca Counties, Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Edwards Limestone Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of the Recommendation

Texas recommends that the following named fields where the Edwards Limestone Formation is encountered be designated as a tight formation. These fields are found along the Gulf coast in the southeastern part of the state in DeWitt, Karnes, and Lavaca Counties, in a portion of Railroad Commission District 2.

DeWitt County: Yoakum (Edwards) Field
Karnes County: Kenedy, East (Edwards) Field
Lavaca County: Sweethome (Edwards) Field
Lavaca County: Word (Edwards) Field
Lavaca County: Word North (Edwards) Field
Lavaca County: Yoakum (Edwards) Field

The Edwards Limestone Formation is massive in thickness. An upper and lower limit can be established across the three county area. In the west, the upper limit may be encountered at

approximately 13,460 feet and in the east, the shallowest depth at which it is found, is approximately 13,150 feet. The base of the Edwards Limestone Formation in the west is located at an undetermined depth. At 14,000 feet, the Edwards Limestone Formation is still apparent which indicates a minimum thickness of approximately 540 feet, while in the east the base appears at an approximate depth of 14,500 feet resulting in a thickness of 1,350 feet. Texas points out that these depths are approximations based on available data.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stablized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given to the proposal submitted by Texas that the Edwards Limestone Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before June 17, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas-10), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than June 2, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(47) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(21) through (46) [Reserved]

(47) *Edwards Limestone Formation in Texas.* RM79–76 (Texas-10)

(i) *Delineation of Formation.* The Edwards Limestone Formation is encountered in the following named fields. These fields are found along the Gulf coast in the southeastern part of the state in DeWitt, Karnes, and Lavaca Counties, Railroad Commission District 2.

DeWitt County: Yoakum (Edwards) Field
Karnes County: Kenedy, East (Edwards) Field
Lavaca County: Sweethome (Edwards) Field
Lavaca County: Word (Edwards) Field
Lavaca County: Word, North (Edwards) Field
Lavaca County: Yoakum (Edwards) Field

(ii) *Depth.* The top of the Edwards Limestone Formation, in the west, is at approximately 13,460 feet and the base is undetermined. In the east, the top of the formation is at an approximate depth of 13,150 feet and the base is the 14,500 feet resulting in a thickness of approximately 1,350 feet.

¶ 32,137 High-Cost Gas Produced From Tight Formations (Utah-1)

46 F. R. 27965 (May 22, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Utah-1)]

High-Cost Gas Produced From Tight Formations; Proposed Rulemakinng

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Utah Board of Oil, Gas and Mining and the United States Geological Survey that the Wasatch/Mesaverde Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on June 17, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on June 2, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307 or Victor Zabel, (202) 357-8616.

Issued: May 18, 1981.

I. Background

On May 11, 1981, the State of Utah Board of Oil, Gas and Mining and the United States Geological Survey (Utah) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Wasatch/Mesaverde Formation located in Uintah County, Utah, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Utah's recommendation that the Wasatch/Mesaverde Formation be designated a tight formation should be adopted. Utah's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies certain lands in the Bitter Creek-Red Wash area of Uintah County, Utah, approximately 25 miles southeast of the town of Roosevelt, Utah. The recommended area contains 448,000 acres located in the general area of Townships 7 South through 12 South and Ranges 18 East through 25 East.

Approximately 85 percent of this land is federal, 11 percent state and 4 percent fee. The average depth to the top of the Wasatch/Mesaverde Formation is 4,559 feet. The average gross productive interval averages approximately 1,150 feet in thickness.

III. Discussion of Recommendation

Utah claims in its submission that evidence gathered through information

and testimony presented at a public hearing in Cause No. TGF-100 convened by Utah on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 milidarcy;

(2) The stablized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Utah further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Utah that the Wasatch/Mesaverde Formation, as described and delineated in Utah's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before June 17, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Utah-1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than June 2, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Utah's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(52) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(25) through (51) [Reserved]

(52) *Wasatch/Mesaverde Formation in Utah* RM79-76 (Utah-1)

(i) *Delineation of formation.* The Wasatch/Mesaverde Formation is found

in the Bitter Creek-Red Wash area of Uintah County, Utah and is the general area of Townships 7 South through 12 South and Ranges 18 East through 25 East.

(ii) *Depth.* The average depth to the top of the Wasatch/Mesaverde Formation is 4559 feet.

¶ 32,138 High-Cost Gas Produced From Tight Formations (Wyoming-4)

46 F. R. 27966 (May 22, 1981).

18 CFR Part 271

[Docket No. Rm79-76 (Wyoming-4)]

High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive incentive price (18 CFR 271.703). This rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Wyoming Oil and Gas Conservation Commission that the Fox Hills Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on June 17, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on June 2, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307 or Victor Zabel, (202) 357-8616.

Issued: May 18, 1981.

I. Background

On May 5, 1981 the State of Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Fox Hills formation located in Sweetwater County, Wyoming, be designated as a tight formation. Pursuant to § 2271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Wyoming's recommendation that the Fox Hills Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Wyoming's recommendation. Wyoming's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of the Recommendation

The recommended formation is located in Sweetwater County, Wyoming in the southern portion of the Green River Basin, south of the town of Table Rock. The area is described as encompassing Township 16 North, Ranges 97 through 99 West; Township 17 North, Ranges 96 through 98 West; Township 17 North, Range 99 West, Sections 24 through 28 and 33 through 36. Township 18 North, Ranges 96 and 97 West; and Township 18 North, Range 98 West, Sections 24 through 26 and 34 through 36.

The vertical limits of the Fox Hills Formation are defined by the Lance

Formation above and the Lewis shale below. The average depth to the top of the formation is 7,412 feet.

III. Discussion of Recommendation

Wyoming claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. 1, Docket No. 69–80, convened by Wyoming on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 milidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Wyoming further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Wyoming that the Fox Hills formation, as described and delineated in Wyoming's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before June 17, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Wyoming-4), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than June 2, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Wyoming's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(51) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(25) through (50) [Reserved]

(51) *Fox Hills Formation in Wyoming* RM79-76 (Wyoming-4)

(i) *Delineation of formation.* The Fox Hills Formation is found in Sweetwater County, Wyoming, in Township 16 North, Ranges 97 through 99 West; Township 17 North, Ranges 96 through 98 West; Township 17 North, Range 99 West, Sections 24 through 28 and 33 through 36; Township 18 North, Ranges 96 and 97 West; and Township 18 North, Range 98 West, Sections 24 through 26 and 34 through 36.

(ii) *Depth.* The Fox Hills Formation vertical limits are defined by the Lance Formation above and the Lewis Shale below. The average depth to the top of the Fox Hills Formation is 7,412 feet.

¶ 32,139 High-Cost Gas Produced From Tight Formations (Utah-2)

45 F. R. 30833 (June 11, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Utah-2)]

High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Utah Board of Oil, Gas and Mining that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on July 6, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on June 22, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

Issued: June 5, 1981.

I. Background

On May 20, 1981, the State of Utah Board of Oil, Gas and Mining (Utah) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Mancos "B" Formation located in Uintah and Grand Counties, Utah, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Utah's recommendation that the Mancos "B" Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Utah's recommendation. Utah's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is part of the Southeast Uintah Basin and underlies certain lands in Uintah and Grand Counties in eastern Utah, 40 to 80 miles northwest of Grand Junction, Colorado. The recommended area contains 428,976 acres within Townships 13 through 16 South, Ranges 20 through 26 East. Approximately 82 percent of the acreage is Federal, 15 percent is State, and three percent is fee. The average depth to the top of the Mancos "B" Formation is 3,475 feet. The average net productive interval is approximately 120 feet.

III. Discussion of Recommendation

Utah claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. TGF-101 convened

by Utah on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Utah further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Utah that the Manco "B" Formation, as described and delineated in Utah's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before July 6, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Utah-2), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission.

Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than June 22, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Utah's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (53) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(37) through (52) [Reserved]

(53) *Mancos "B" Formation in Utah* RM79-76 (Utah-2)

(i) *Delineation of formation.* The Mancos "B" Formation is found in the Southeast Uinta Basin underlying

portions of Uintah and Grand Counties, Utah in Township 13 South, Ranges 20 through 22 East, Sections 31 through 36; Township 13 South, Ranges 23 through 26 East, All Sections; Township 14 and 15 South, Ranges 20 through 26 East, All Sections; Township 15½ South, Ranges 23 through 25 East, Sections 31 through 36; Township 15½ South, Range 26 East, Sections 31 through 33; Township 16 South, Ranges 23 and 24 East, All Sections; Township 16 South, Range 25 East, Sections 1 through 12; and Township 16 South, Range 26 East, Sections 4 through 9.

(ii) *Depth.* The average depth to the top of the Mancos "B" Formation is 3,475 feet.

¶ 32,140 High-Cost Gas Produced From Tight Formations (Wyoming-5)

46 F. R. 32270 (June 22, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming—5)]

High-Cost Gas Produced from Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 C.F.R. § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Wyoming that the Frontier Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on July 16, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on July 1, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

Issued June 16, 1981.

In the matter of high-cost gas produced from tight formations; Docket No. RM79-76 (Wyoming—5).

I. Background

On June 8, 1981, the State of Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Frontier Formation located in Carbon County, Wyoming, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Wyoming's recommendation that the Frontier Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Wyoming's recommendation. Wyoming's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies portions of Carbon County, Wyoming. The proposed area contains 55,040 acres and is located generally within Townships 14 through 16 North, Ranges 89 through 91 West, approximately 30 miles south of the town of Rawlins, Wyoming. The depth to the top of the Frontier Formation ranges from approximately 5500 feet on the eastern edge of the area to approximately 7500 feet on the western edge, and is expected to average 6000 feet. The Frontier Formation averages 250 feet in thickness.

III. Discussion of Recommendation

Wyoming claims in its submission that evidence gathered through information and testimony presented at a public hearing in Docket No. 193-80

convened by Wyoming on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Wyoming further asserts the existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Wyoming that the Frontier Formation, as described and delineated in Wyoming's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before July 16, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Wyoming—5), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission.

Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than July 1, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Wyoming's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (54) to read as follows:

§ 271.703 Tight formations.

* * * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation. * * *

(40) through (53) [RESERVED]

(54) *Frontier Formation in Wyoming* RM79-76 (Wyoming—5)

(i) *Delineation of formation.* The Frontier Formation is located in Carbon County, Wyoming, in Township 14 North, Range 89 West, Sections 5 through 8, 17 through 20, 29 and 30; Township 14 North, Range 90 West,

Sections 1 through 5, 8 through 17, and 21 through 28; Township 15 North, Range 89 West, Sections 18 through 20 and 29 through 32; all of Township 15 North, Range 90 West, excluding Sections 1 and 31; Township 15 North, Range 91 West, Sections 1 and 12; Township 16 North, Range 90 West, Sections 19, 20, and 28 through 34; and Township 16 North, Range 91 West, Sections 24, 25, and 36.

(ii) *Depth.* The top of the Frontier Formation is found at depths ranging from 5,500 feet in the east to 7,500 feet in the west, and averaging 6,000 feet. The Frontier Formation is defined as that formation found immediately beneath the Carlile Shale and immediately above the Mowry Shale.

¶ 32,141 High-Cost Gas Produced From Tight Formations (Wyoming-6)

46 F. R. 32596 (June 24, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming—6)]

Wyoming; High-Cost Gas Produced from Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Wyoming Oil and Gas Conservation Commission that the Bear River Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on July 20, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on July 6, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

SUPPLEMENTARY INFORMATION: Issued: June 18, 1981.

I. Background

On June 8, 1981, the State of Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Bear River Formation located in Lincoln, Sweetwater, and Sublette Counties, Wyoming, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Wyoming's recommendation that the Bear River Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Wyoming's recommendation. Wyoming's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located in the Northern Moxa Arch area of Southwestern Wyoming approximately 10 miles southeast of Big Piney, Wyoming. The area contains about 199,665 acres within Lincoln, Sweetwater, and Sublette Counties, Wyoming, encompassing Townships 25 through 28 North, Ranges 110 and 111 West and the eastern two-thirds of Township 28 North, Range 112 West.

The vertical limits of the Bear River Formation are defined by the Mowry Shale Formation above and the Thermopolis Shale Formation below. The depth to the top of the formation varies from 9,400 feet to 11,200 feet. The average net productive interval is approxiamtely 20 feet.

III. Discussion of Recommendation

Wyoming claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. 1, Docket No. 189–80(B) convened by Wyoming on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Wyoming further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Wyoming that the Bear River Formation, as described and delineated in Wyoming's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before July 20, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Wyoming—6), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.W., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than July 6, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Wyoming's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (55) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(40) through (54) [Reserved]

(55) *Bear River Formation in Wyoming.* RM79–76 (Wyoming—6).

(i) *Delineation of formation.* The Bear River Formation is found in Lincoln, Sweetwater, and Sublette Counties, Wyoming, in Townships 25 through 28 North, Ranges 110 and 111 West; and Township 28 North, Range 112 West, Sections 1 through 4, 9 through 16, 21 through 28 and 33 through 36.

(ii) *Depth.* The Bear River Formation vertical limits are defined by the Mowry Shale Formation above and the Thermopolis Shale Formation below. The depth to the top of the Bear River Formation varies from 9,400 feet to 11,200 feet.

¶ 32,142 High-Cost Gas Produced From Tight Formations (Wyoming-7)

46 F. R. 32597 (June 24, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming—7)]

Wyoming; High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designting natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Wyoming Oil and Gas Conservation Commission that the Frontier Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on July 20, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on July 6, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

Issued: June 18, 1981.

I. Background

On June 8, 1981, the State of Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 F.R. 56034, August 22, 1980), that the Frontier Formation located in Lincoln, Sweetwater, and Sublette Counties, Wyoming, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Wyoming's recommendation that the Frontier Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Wyoming's recommendation. Wyoming's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located in the Northern Moxa Arch area of Southwestern Wyoming approximately 10 miles southeast of Big Piney, Wyoming. The area contains about 199,665 acres and is in Lincoln, Sweetwater, and Sublette Counties, Wyoming, encompassing Townships 25 through 28 North, Ranges 110 and 111 West and the Eastern two-thirds of Township 28 North, Range 112 West.

The vertical limits of the Frontier Formation are defined by the Baxter Shale Formation above and the Mowry Shale Formation below. The depth to the top of the formation varies from 9,000 feet to 10,500 feet. The average net productive interval is approximately 31 feet.

III. Discussion of Recommendation

Wyoming claims in its submission that evidence gathered through

information and testimony presented at a public hearing in Cause No. 1, Docket No. 189–80(A) convened by Wyoming on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B): and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Wyoming further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Wyoming that the Frontier Formation, as described and delineated in Wyoming's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before July 20, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Wyoming—7), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than July 6, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Wyoming's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (56) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(40) through (55) [Reserved]

(56) *Frontier Formation in Wyoming.* RM79–76 (Wyoming—7).

(i) *Delineation of formation.* The Frontier Formation is found in Lincoln, Sweetwater, and Sublette Counties, Wyoming, in Townships 25 through 28 North, Ranges 110 and 111 West; and Township 28 North, Range 112 West, Sections 1 through 4, 9 through 16, 21 through 28 and 33 through 36.

(ii) *Depth.* The Frontier Formation vertical limits are defined by the Baxter Shale Formation above and the Mowry Shale Formation below. The depth to the top of the Frontier Formation varies from 9,000 feet to 10,500 feet.

¶ 32,143 High-Cost Gas Produced From Tight Formations (Pennsylvania-1)

46 F. R. 35119 (July 7, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Pennsylvania—1)]

Pennsylvania, High Cost Gas Produced from Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Pennsylvania Department of Environmental Resources, Bureau of Topographic and Geologic Survey that the Medina Group be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on July 29, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on July 15, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Roy Johnson, (202) 357-8731.

SUPPLEMENTARY INFORMATION:

Notice of Proposed Rulemaking by Director, OPPR

Issued June 29, 1981.

I. Background

On June 8, 1981, the Pennsylvania Department of Environmental Resources, Bureau of Topographic and Geologic Survey (Pennsylvania) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Medina Group located in northwestern Pennsylvania be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Pennsylvania's recommendation that the Medina Group be designated as a tight formation should be adopted. Pennsylvania's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Pennsylvania recommends that the Medina Group encountered in Erie, Crawford, Mercer, Venango, and Warren Counties, Pennsylvania be designated as a tight formation. The recommendation includes only those portions of the Medina Group which Pennsylvania designated as meeting tight formation guidelines. The Grimsby Sandstone, Cabot Head Shale, Manitoulin Dolomite where present, and the Whirlpool Sandstone comprise the Medina Group, a sequence of interbedded sandstones, siltstones, and shales of the Lower Silurian System in northwestern Pennsylvania. Regionally,

the Medina Group dips to the southeast approximately 50 feet per mile. Net sandstone thickness (50% Gamma-Ray cutoff) is a maximum of 80 to 100 feet. The Medina Group extends southeastward to where the Whirlpool Sandstone is truncated in Warren, Forest, Clarion, Armstrong, Butler and Beaver Counties by an apparent unconformity.

III. Discussion of Recommendation

Pennsylvania's recommendation contains information, submitted by the Pennsylvania Oil and Gas Association—Gas Advocacy Committee in its application for designation of the Medina Group as a tight formation, which indicates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Pennsylvania states that, "* * * while the Pennsylvania Clean Streams Law prohibits pollution of all Pennsylvania waters, inadequate enforcement capabilities and the absence of specific oil and gas drilling and operation regulations prevent us from providing assurance that fresh water aquifers will not be adversely affected by development of tight formations."

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Pennsylvania that portions of the Medina Group, as described and delineated in Pennsylvania's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting writting data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before July 29, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Pennsylvania-1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than July 15, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Pennsylvania's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (57) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(45) through (56) [RESERVED]

(57) *Medina Group in Pennsylvania.* RM79–76 (Pennsylvania–1).

(i) *Delineation of formation.* The Medina Group is found in Erie, Crawford, Mercer, Venango and Warren Counties, Pennsylvania.

(ii) *Depth.* The Medina Group is defined as that formation occurring within the Lower Silurian System between the Reynales Dolomite and the Queenston shale found at an approximate depth of 3,000 feet in the updip area, dipping to the southeast at approximately 50 feet per mile.

¶ 32,144 Revision of Form No. 80, Licensed Projects Recreation Report

46 F. R. 35298 (July 8, 1981)

18 CFR Parts 8 and 141

[Docket No. RM81-36]

Proposed Rulemaking To Revise Form No. 80, Licensed Projects Recreation Report

Issued: July 2, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its Form No. 80, Licensed Projects Recreation Report. Form No. 80 biennially collects information about recreational facilities and recreational opportunities at developments within hydroelectric projects which are licensed by the Commission.

As proposed, certain data requests contained in the form would be consolidated, simplified and clarified and the form itself would be reduced in size by about 60 percent. The proposed revision of Form No. 80 is part of the Commission's ongoing program to eliminate reporting requirements which are not necessary to the performance of the Commission's regulatory responsibilities and to reduce the burden associated with necessary filing requirements.

DATE: Comments are due by August 3, 1981.

ADDRESSES: Comments to this Notice should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM81-36.

Copies of the Form No. 80 are available at: Federal Energy Regulatory Commission, Office of Public Information, 825 North Capitol Street NE., Room 1000, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

John O. Young, Jr., Office of Electric Power Regulation, 825 North Capitol Street NE., Room 308RB, Washington, D.C. 20426, (202) 376-4312.

SUPPLEMENTARY INFORMATION:

Issued: July 2, 1981.

I. Introduction

The Federal Energy Regulatory Commission (Commission) proposes to amend its regulations at 18 CFR 8.11, and the Form No. 80, the Licensed Projects Recreation Report which is prescribed by § 8.11.[1] Form No. 80 solicits information about recreational facilities and recreational opportunities at developments within hydroelectric projects licensed by the Commission under the Federal Power Act.[2] These data are used to determine whether the public need for water-based recreation facilities is being met by such licensees and whether additional efforts should be made to meet current and future recreational needs.

Form No. 80 is collected from about 160 project licensees. The form is required to be submitted every other year, although it collects data only for the year immediately preceding the year in which it is filed.

[1] Form No. 80 (Appendix) is not being printed by the Federal Register. Copies of Form No. 80, including all instructions to the form are available at the Commission's Office of Public Information.

[2] The Commission is authorized to issue licenses for hydropower projects pursuant to sections 3 and 4 of the Federal Power Act (16 U.S.C. 796, 797). The Commission collects information in the Form No. 80 pursuant to section 304 of the Federal Power Act (16 U.S.C. 825c). For purposes of the Form No. 80, each development within a project consists of a reservoir or generating station and related waterways.

This rulemaking proceeding has been initiated as part of the Commission's ongoing program to review Commission filing requirements and reduce unnecessary reporting burdens. The Form No. 80 has been prescribed by Commission regulations since 1967.[3] As a result of reevaluation of the form, the Commission has determined that certain items are not necessary to the performance of the Commission's regulatory responsibilities. Accordingly, the Commission proposes to reduce the number of data elements in the form by approximately 60 percent. This should result in a net decrease of 75 percent in the time it takes for respondents to collect data for each form, record it, and submit it to the Commission. The time needed to complete a Form No. 80 would be reduced from the current 40 hours to only 10 hours.

In addition, the procedure for filing the form would be simplified. As is currently required, respondents would have to make only one complete filing of the revised Form No. 80. Subsequent filings would be updated only to the extent necessary to "change, delete or add to" the previously submitted information. since the Commission would preprint and return to respondents those forms previously filed, changes to the information could then be made quickly and easily.

Finally, respondents would no longer be required to list under "Other" all those facilities at a development which are not designated on the form. Reports would be required only for the facilities which are specifically named on the form.

II. Summary of Proposed Changes

A. Revisions to Form No. 80

The Commission proposes to completely redesign Form No. 80 in order to consolidate and clarify necessary data requirements, eliminate unnecessary elements and update certain of the reporting requirements. The title of Form No. 80 would be changed from "Licensed Projects Recreation Report" to "Licensed Hydropower Development Recreation Report" to better describe the source of information for the report. For the same reason, references to "project" would be changed to "development" elsewhere in the form and in the regulations. The instructions would also provide that the form would be preprinted for submissions made after the 1981 filing so that respondents would simply note changes as necessary.

The following items would be deleted from Form No. 80:[4]

Direction and air miles from the project to the nearest city (Part 2.D.)
Estimated population within 100 air miles of the development (Part 2.E.)
Location of the center of the project development in latitude and longitude (part 2.H.)
Maximum pool fluctuation (in feet, Msl) (Part 3.E.)
Water quality and description (Part 3.F.)
Description of (1) reservoir operation, (2) accessibility, (3) climate, and (4) nearly recreation areas (Part 3.H.)
Total days in recreation season (Part 3.J. (3))
Land and water control policy (Part 4.a. (5))
Names and addresses of cooperating agencies (Part 4.B.)
Types of recreation fees and range of charges in project (Part 4.D.)
Initial number of annual visitations to the development (Part 5.b.)
Initial number of visitors on an average peak weekend day (Part 5.E.)
Land and land rights (Part 6.A.)
Structures, improvements and equipment (Part 6.B.)
Gross recreation investment (Part 6.C.)
Total development investment (Part 6.E.)
Initial number of free and user fee facilities in the project (Part 7. Cols. 3 and 4.)
The reason why no comfort stations are provided; whether or not comfort stations meet local standards and if not, the reason why (Part 8.B.)

[3] Docket No. R-276, Order No. 330, issued December 12, 1966 (31 FR 16201, December 17, 1966), codified at 19 CFR 8.11 and 141.14 [1980].

[4] All references to Part number and item are from the current Form No. 80.

The reason why waste and sanitary disposal features are not provided; whether or not they meet local requirements and if not, the reason why (Part 8.C.)
The reason why drinking water is not provided (Part 8.D.)
Reports of the number of fishing camps, quest ranches, private clubs and airfields which are operated by others on land adjoining the project. (Part 9.D., H., K., M.
Date of signature by person making the report (Part 10.)

The following items would be added to the form to reflect changes in the types of facilities provided within the development boundary and on lands adjoining the project:[5]

Boat launching lanes
Trailer/RV sites
special purpose recreational areas
Hunting areas
Cultural resource sites
Overnight lodging units
Overlooks
Winter sports facilities

B. Amendments to 18 CFR 8.11

The regulations at § 8.11 would be revised in three important respects:

First, the procedure for filing the Form No. 80 would be changed. Section 8.11(a) would provide that the FERC Form No. 80 must be completed in its entirety by all licensees who are required to file the form by November 30, 1981 (consistent with the current requirement). By this rulemaking, however, any filings of Form No. 80 made after November 30, 1981, including initial (first time) filings of the form, would be required by February 28 of each odd-numbered year. The February date was chosen so that reports which are based on information collected through December 31 of each even-numbered year could be filed on a timely basic.

Second, § 8.11(b) would be revised to reflect changes in other portions of the Commission regulations persuant to requirements in the Public Utility Regulation Policies Act of 1978 (PURPA) (16 U.S.C. 2601–2845).[6]

Section 8.11(b) currently provides for the postponement in the filing of an initial Form No. 80 if an applicant has filed a recreational use plan or an exhibit pursuant to 18 CFR 4.41. Section 4.41 was one of the provisions which was revised as a result of PURPA. Before the passage of PURPA, § 4.41 exhibits could be applied to either constructed *or* unconstructed projects. Since passage of PURPA, however, the exhibits associated with *unconstructed* projects are prescribed at § 4.41 and exhibits which pertain to *existing* (constructed) projects are prescribed at § 4.51

This rulemaking would, therefore, revise § 8.11(b) to reflect the changes resulting from PURPA pertaining to postponements in filing Form No. 80 for unconstructed and existing projects. Licensees of *unconstructed* projects would be required to file an initial Form No. 80 only after the project has been in operation for a full calendar year prior to the submission date. Licensees of *existing* (constructed) projects, however, would have to file an initial Form No. 80 only after the project has been licensed for a full calendar year prior to the submission date.

Finally, the only noteworthy revision to § 8.11(c) would be the substitution of the word "development" for "project" to better describe the source of information for the form.

[5] The new items proposed for Form No. 80 have frequently been reported as "other" facilities at a development. All requirements to specify any "other" facilities on the form have been eliminated. Because the names of the frequently-reported facilities would be printed on the form, the respondents' reporting burdens would be further reduced because they would only have to report on those items listed in the form.

[6] Section 405 of PURPA requires that simple licensing procedures be established by the Commission for small hydroelectic projects at existing dams. The Commission made appropriate revisions to its regulations which prescribe hydroelectric licensing requirements in order to satisfy this PURPA directive. *See* Docket No. RM79–23, Order No. 54, issued October 22, 1979 (44 FR 61336, October 25, 1979), and Docket No. RM79–36, Order No 59, issued November 19, 1979 (44 FR 67651, November 27, 1979).

II. Initial Regulatory Flexibility Analysis

This initial regulatory flexibility analysis is prepared pursuant to the Regulatory Flexibility Act (RFA),[7] which requires certain statements, descriptions, and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities". The broad purpose of the RFA is to ensure more careful and informed agency consideration of rules which may significantly affect small business and small government entities, and to encourage cost-benefit analyses of these rules as well as the agency's consideration of alternative approaches which may better resolve any unnecessarily costly or adverse effects on these small entities.

In Parts I and II of the preamble of the instant proposal, the Commission has presented its reasons for agency action, and its objectives and the legal basis for the rulemaking, and the reporting, recordkeeping, and other compliance requirements which it imposes, in accordance with the requirements of section 603(b)(1), and (2) and (4) of the RFA. In further compliance with section 603(b)(4), the Commission notes that no special expertise is necessary to comply satisfactorily with this proposed rule's filing requirements. In sum, the proposed rule would reduce substantially the reporting burden of *all* respondents (*i.e.*, both small and large entities) who file reports pursuant to § 8.11 of the Commission's regulations.

The proposed rule would redesign, simplify, and update the data in Form No. 80, the Licensed Projects Recreation Report; reduce the number of data elements therein by approximately 60 percent and provide for preprinting of the forms in the future. The changes would reduce by 75 percent the time required of each of the respondents to collect and record the necessary data; thus, instead of the approximately 40 hours it currently takes to complete each Form No. 80, it would now take only about 10 hours per form. This time saving should result in a significant economic saving as well.

Additional benefits to licensees of small projects were realized in Commission Order No. 106 (Docket No. RM80–65, November 7, 1980, 45 FR 76115, November 18, 1980). Order No. 106 establishes Subpart K in Part 4 of the Commission regulations pursuant to section 408 of the Energy Security Act of 1980 (Pub. L. 96–294, 94 Stat. 611) and provides an exemption from licensing procedures for projects with an installed capacity of 5 megawatts or less. These new regulations will reduce by about 50 the number of potential Form No. 80 respondents. The Commission believes the proposed changes are beneficial in that they will significantly reduce the reporting burden and related costs for small business entities.

Section 603(b)(3) and (4) of the RFA requires a description and, if possible, an estimate of the number of small entities subject to the proposed rule. Currently, there are about 160 respondents (licensees) which are required to file the Form No. 80 for developments in one or more projects. Approximately 50 of these are small entities[8] (including municipalities under 50,000 population). Some small entities file only one form per project because the development actually constitutes the entire project. Larger entities may file several forms because they hold licenses for more projects and each project may contain several developments.

Section 603(c) of the RFA requires a description of significant alternatives to the proposed rule that may help minimize the proposal's adverse economic impact on small entities. From

[7] 5 U.S.C 601–612.

[8] In the context of this small entity impact analysis, small entities are considered Class C or Class D licensees. The annual revenues of Class C entities are $150,000 or more but less than $1,000,000, and Class D licensees earn revenues of $25,000 or more but less than $150,000. (See 18 CFR Part 101, Uniform System of Accounts Prescribed for Public Utility and Licensees Subject to the Provisions of the Federal Power Act.)

the viewpoint of regulatory flexibility, the significant alternatives to the proposed rules are to first, leave the existing provisions intact or second, to further reduce the reporting requirement.

The first alternative (leave the existing provisions intact) would contradict the objectives of the RFA. The primary purpose of this rulemaking is to reduce the reporting burdens from the current requirements. This can only be accomplished by Commission action, such as that proposed in this docket.

With respect to the second alternative (further reduce the reporting requirement), this form has undergone extensive review over a period of five or six years. The data elements have been pared to an essential minimum in light of the intent of the Federal Power Act and the Commission's regulatory responsibilities specified therein. Therefore the Commission cannot justify a further reduction in data reporting for small entities and perform an adequate oversight of such licensees.

As a third alternative for the instant rulemaking, the Commission might propose changing § 8.11(c) of the regulations. Paragraph (c) provides an exemption from the filing of Form No. 80 for licensees of projects having no recreational use. The Commission might, instead, provide an exemption for licensees of projects wherein the recreational usage is below a predetermined amount (*e.g.*, less than 1,000 visits per year). The Commission believes that this is not a reasonable alternative because it would contradict the statutory requirement in section 10(a) of the Federal Power Act which provides that each project licensed by Commission "* * * will be best adapted to a comprehensive plan for improving and developing a waterway or waterways, for * * * beneficial public uses, including recreational purposes".

Finally, in compliance with section 609 of the RFA, the Commission will send copies of this Notice of Proposed Rulemaking to each project licensee who is required to file this form for review and comment.

IV. Written Comment Procedure

The Commission invites interested persons to submit written data, views and other information concerning the matters set out in this Notice. An original and 14 copies of such comments should be filed with the Commission by August 3, 1981. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM81-36.

All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426 during regular business hours.

(Department of Energy Organization Act, 42 U.S.C. 7101-7352; E.O. 12009, 3 CFR 142; Federal Power Act, 16 U.S.C. 792-828c; Public Utility Regulatory Policies Act, 16 U.S.C. 2601-2645)

In consideration of the foregoing, the Commission proposes to amend Form No. 80 as set forth in Attachment A, and Parts 8 and 141 of Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

1. Section 8.11 is revised to read as follows:

§ 8.11 Information respecting Use and Development of Public recreational opportunities.

(a)(1) *Applicability.* Except as provided in paragraph (b) of this section, each licensee of a project under major or minor Comission license shall prepare with respect to each development within such project an original and two conformed copies of FERC Form No. 80 prescribed by § 141.14 of this chapter.

(2) The Form No. 80 is due on November 30, 1981, for data compiled during the calendar year ending December 31, 1980. Thereafter, this

report is due on February 28 of each odd-numbered year for data compiled during the previous calendar year.

(3) The Form No. 80 shall be completed in its entirety:

(i) for each report due on November 30, 1980, or

(ii) for each initial filing of the report.

(4) Filings of Form No. 80 made subsequent to reports filed pursuant to paragraph (a)(3) of this section shall be completed only to the extent necessary to change, delete or add to the information supplied in a previously filed form.

(5) One copy of the Form No. 80 should be retained by the respondent licensee in its file.

(b) *Initial Form No. 80 Filings.* Each licensee of an unconstructed project shall file an initial Form No. 80 after such project has been in operation for a full calendar year prior to the filing deadline. Each licensee of an existing (constructed) project shall file an initial Form No. 80 after such project has been licensed for a full calendar year prior to the filing deadline.

(c) *Exemptions.* A licensee may request an exemption from any further filing of Form No. 80 for any development which has no existing or portential recreational use by submitting a statement not later than 6 months prior to the due date for the next filing, stating that Form No. 80 has been filed previously for such development, and setting out the basis for believing that the development has no existing or potential recreational use.

2. Section 141.14 is revised to read as follows:

§ 141.14 Form No. 80, Licensed Hydropower Development Recreation Report.

The form of the report, Licensed Hydropower Development Recreation Report, designated as FERC Form No. 80, for use by licensees in reporting information with respect to existing and potential recreational use at developments within projects under major and minor license, is approved and prescribed for use as provided in § 8.11 of this chapter.

¶ 32,145 High-Cost Gas Produced From Tight Formations (Texas-11)

46 F. R. 38934 (July 30, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas-11)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designated certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Railroad Commission of Texas that the Wilcox Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on August 24, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on August 10, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson, (202) 357-8556.

Issued July 24, 1981.

In the matter high-cost gas produced from tight formations, Docket No. RM79-76 (Texas-11), notice of proposed rulemaking by director, OPPR.

I. Background

On June 24, 1981, the Railroad Commission of Texas (Texas) submitted by the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Wilcox Formation in Webb County, Texas be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is nearby issued to determine whether Texas' recommendation that the Wilcox Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Wilcox Formation in the area of the Aviators, N. (12,000) Field in the southern portion of Webb County, Texas, Railroad Commission District 4, be designated as a tight formation. The area recommended is within a 2.5 mile radius around the Pennzoil Producing Company No. 53-1 B.M.T.—Alice B. Hall well and covers approximately 19.6 square miles. The top of the recommended formation is at approximately −11,085 feet subsea, and has a gross thickness of 114 feet.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered and presented at a

public hearing in support of this recommendation demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Wilcox Formation as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before August 24, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas-11), and should give reasons including supporting data for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than August 10, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (58) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formation. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(48) through (57) [Reserved]

(58) *Wilcox Formation in Texas.* RM79-76 (Texas-11).

(i) *Delineation of formation.* The Wilcox Formation is found in the area of the Aviators, N. (12,000) Field, Webb County, Texas and the recommended area is within a 2.5 mile radius around the Pennzoil Producing Company No. 53–1 B.M.T.—Alice B. Hall well and covers approximately 19.6 square miles.

(ii) *Depth.* The top of the Wilcox Formation is at approximately—11,085 feet subsea and is 114 feet thick.

¶ 32,146 High-Cost Gas Produced From Tight Formations (Texas-9 Addition)

46 F. R. 38935 (July 30, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-9 Addition)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that an additional area of the Travis Peak Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on August 24, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on August 10, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson, (202) 357-8556.

Issued: July 24, 1981.

In the matter of high-cost gas produced from tight formations, Docket No. RM79-76, (Texas-9 Addition), notice of proposed rulemaking by Director, OPPR.

I. Background

On June 17, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that an additional area of the Travis Peak Formation located in the Bear Grass area, in the eastern part of the State of Texas, be designated as a tight formation. The Commission previously adopted a recommendation that the Travis Peak Formation in the Sym-Jac West (Hosston) Field be designated as a tight formation (RM79-76 Texas-9, Order No. 154 issued June 10, 1981). Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Travis Peak formation in the Bear Grass area be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Travis Peak Formation in the Bear Grass area, encountered in east Texas in portions of Freestone and Leon Counties, Texas, Railroad Commission District 5, be designated as a tight formation.

The area recommended for designation entails an ellipse whose major axis runs approximately 3.8 miles in a northeast/southwest orientation,

and whose minor axis runs approximately 1.6 miles in a northwest/southeast orientation, and contains approximately 5 square miles. The point of intersection of the major and minor axes of the particular area being recommended is located approximately 10,000 feet (2 miles) east of the point of intersection of Freestone, Leon, and Limestone Counties. The Travis Peak Formation is the basal formation of the Lower Cretaceous series and overlies the Jurassic Cotton Valley Sands and is below the Pettit Formation.

The total formation thickness in this area is approximately 3,100 feet in the four wells in the area which penetrated the Travis Peak Formation. The approximate top and base of the formation in the recommended area are at −8,379 feet and −11,462 feet (below sea level), respectively. Most of the gas production is from the upper 500 feet of the formation.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Travis Peak Formation in the Bear Grass area, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before August 24, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas -9 Addition) and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 confirmed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than August 10, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below,

in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulations.

1. Section 271.703(d) is amended in subparagraph (36) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formation is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation. * * *

(36) *Travis Peak Formation in Texas.* RM79–76 (Texas –9).

(i) *Sym-Jac, West (Hosston) Field.*

(A) *Delineation of formation.* The Travis Peak Formation in the Sym-Jac, West (Hosston) Field is found in Cherokee County, Texas, Railroad Commission District 5.

(B) *Depth.* The top and base of the Travis Peak Formation are found at approximately 9,850 feet and 12,050 feet, respectively, giving it a thickness of approximately 2,200 feet.

(ii) *Bear Grass Area.*

(A) *Delineation of formation.* The Travis Peak Formation in the Bear Grass area is found in portions of Freestone and Leon Counties, Texas, Railroad Commission District 5. The area is elliptical with a northeast/southwest major axis and contains approximately 5 square miles. The center of the area is approximately 2 miles east of the point of intersection of Freestone, Leon and Limestone Counties and is situated in portions of the following surveys: Gertrude Diaz A–178 and A–1276, Isaac Connelly A–117 and A–1152, William F. Gray A–296, L. W. Gideon A–1018 and Thomas Hardee A–1022.

(B) *Depth.* The top and base of the Travis Peak Formation are found at approximate subsea depths of −8,379 feet and −11,482 feet, respectively, giving a thickness of approximately 3,100 feet.

¶ 32,147 Inclusion of Construction Work in Progress for Public Utilities

46 F. R. 39445 (August 3, 1981); 46 F. R. 45624 (September 14, 1981).

18 CFR Parts 2 and 35

[Docket No. RM81-38]

Inclusion of Construction Work in Progress for Public Utilities

Issued: July 27, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission proposes to amend its regulations regarding the inclusion of construction work in progress (CWIP) in the rate base of public utilities to relieve severe financial difficulty. The proposed rule is intended to clarify the Commission's policy on CWIP and to avoid protracted litigation on this issue before the Commission.

DATES: Written comments must be received on or before September 23, 1981. Reply comments must be received on or before October 23, 1981.

ADDRESSES: Copies of the comments may be obtained from the Division of Public Information, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8055. Comments must be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Ronald L. Rattey, Office of Regulatory Analysis, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, Room 3000F, (202) 357–8186 or

Robert P. Shapiro, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, Room 8000E, (202) 357–8455 or

Christine P. Benagh, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, Room 8104B, (202) 357–8606

SUPPLEMENTARY INFORMATION:

I. Introduction

The Federal Energy Regulatory Commission (Commission) [1] proposes to amend its regulations concerning construction work in progress (CWIP) for public utilities by replacing the current § 2.16 (inclusion of construction work in progress in rate base of electric utilities) with a new Subpart D in Part 35 (Filing of Rate Schedules). A proposed rule is published in this notice. In addition, in Section III of this preamble we discuss and request comments on alternative changes to our existing rule relating to CWIP.

The proposed rule published in this notice does not change the substance of the provisions of § 2.16 under which CWIP is included in rate base for pollution control and fuel conversion facilities nor the requirement that a utility discontinue capitalization of allowance for funds used during construction (AFUDC) on amounts of CWIP included in rate base. It focuses instead on when CWIP should be allowed in rate base to relieve the severe financial difficulty of a utility. The proposed rule would establish more precise criteria for determining whether a utility qualifies for the inclusion of CWIP in rate base under such

[1] The term "Commission" refers to the Federal Power Commission with respect to actions taken prior to October 1, 1977, and to the Federal Energy Regulatory Commission with respect to any actions on or after that date.

circumstances and for assessing the amount of CWIP that a qualifying utility may include in rate base. It would establish specific grounds upon which the Commission may limit the amount of CWIP that would otherwise be included in rate base under these criteria. Further, it would permit a utility on a claim of severe financial difficulty to collect CWIP in rate base subject to refund. The Commission wishes to make it clear that, although we have proposed here a mechanical rule triggered by low bond ratings and the relationship of CWIP outside of the rate base to the rate base, we intend to explore in this proceeding alternatives of broader scope than financial distress as a basis for allowing CWIP in rate base, as well as alternative formulations based on financial distress.

II. Background

One of the costs of utility plant which a utility recovers from ratepayers is the debt interest and a reasonable equity return on the capital investment used to finance construction. There are two mutually exclusive ratemaking methodologies by which these carrying charges on construction capital may be recovered in rates.

One method capitalizes the carrying charges incurred during the construction period as AFUDC.[3] AFUDC is recorded, in part, as current income to the utility (and as an offset to interest expenses), but no cash payments are made by rate payers during construction. Payments from ratepayers to cover the carrying charges begin when the completed plant goes into operation. The cost of the completed plant at that time includes all carrying charges recorded during the construction period, as well as the direct costs of land, labor and construction materials.[3] The entire cost of the plant (including AFUDC) is added to rate base, and it earns a rate of return on investment and is depreciated over the life of that plant.

The second method for recovering carrying charges incurred during the construction period is to include the uncompleted plant in rate base. The utility recovers its carrying charges (or return) currently from ratepayers, rather than adding them to the cost of construction. The return on CWIP is recorded as income on a current basis (like AFUDC), and actual cash payment are made by the ratepayers currently (unlike AFUDC).

Each method assures the utility of an opportunity to recover from its ratepayers the carrying charges associated with construction investment. The difference between the two concerns the timing of that recovery. However, there are regulatory policy considerations that warrant the selection of one method over the other. AFUDC capitalization of carrying charges provides no immediate "cash flow" to the utility, whereas the inclusion of CWIP in rate base produces immediate revenues. But the CWIP inclusion method produces a mismatch of the benefits of the construction program, which inure to future ratepayers, and the costs of financing that program, which are borne by present customers. The courts generally have deferred to the administrative agency's choice of methods.[4]

The Commission has consistently followed a policy that generally prohibits the inclusion of CWIP in rate base, electing the AFUDC method instead. The plant must be "used and useful," *i.e.*, actually providing service, before it may be included in rate base. This policy recognizes few exceptions, as judicially noted in 1979 by the U.S. Court of Appeals for the District of Columbia Circuit:

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[3] Commission Order Nos. 561 and 561-A govern the manner in which carrying charges are computed and added to the costs of plant under the AFUDC method (issued Feb. 2, 1977, and Aug. 1, 1977 respectively), 42 FR 9161 (1977) and 42 FR 39661 (1977) respectively.

[3] *See* Uniform Systems of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (Class A and Class B), Electric Plant Instructions, 18 CFR Part 101 (1980).

[4] *Goodman v. Public Service Commission*, 497 F. 2d 661, 666 (D.C. Cir. 1974).

[T]he precept endures that an item may be included in rate base only when it is "used and useful" in providing service. In other words, current rate payers should bear only legitimate costs of providing service to them. The FPC early adopted the "used and useful" standard and has not departed from it without careful consideration of the wisdom of requiring current rate payers to bear costs of providing future service.[5]

Three years earlier the Commission has adopted three narrow exceptions to the use of the AFUDC methodology for electric utilities in Order No. 555.[6] That order promulgated a new regulation, § 2.16, which permits CWIP associated with electric utility construction programs of pollution control facilities[7] and fuel conversion facilities[8] to be allowed in the rate base. Section 216 further provides that the Commission will consider including other types of CWIP in rate base in cases where the utility is in "severe financial difficulty which cannot be otherwise alleviated without materially increasing the cost of electricity to consumers." However, only if this demonstration of financial distress is "clearly and convincingly" made will the Commission include some amount of CWIP in rate base.

Implementation of the Commission's current rule on CWIP for financial distress has produced protracted and complex litigation. There have been five applications for special CWIP relief under this standard. One resulted in a finding of financial distress by an administrative law judge,[10] one was settled before hearings commenced,[11] two have been decided by the Commission against CWIP relief (affirming the administrative law judges),[12] and the reamining case was partially settled after CWIP relief was denied by a judge.[13] Three of these proceedings have lasted for three years or more.

In the proposed rule we adhere to the general concept of "severe financial difficulty" as a test for inclusion of CWIP in rate base. However, the specific formulation given to that concept in § 2.16 has not proved to be satisfactory. The financial distress test has been rarely used since its inception. Ironically, the financial condition of the electric utility industry appears to have deteriorated during the same period. In an Informal Conference on the Financial Condition of the Electric Power Industry, held on March 6 of this year, the Commission, sitting with five members of various state regulatory agencies, heard voluminous testimony regarding the financial deterioration of the electric utility industry.[14] Testimony of the worsening of the financial condition of the industry suggests that § 2.16 in its present form may not be an effective mechanism for the relief of seriously

[5] *Tennessee Gas Pipeline Co. v. FERC*, 606 F.2d 1094, 1100–10 (D.C. Cir. 1979) (Footnote omitted).

[6] *Order Adopting in Part Construction Work in Progress Rulemaking and Terminating Proceedings*, Order No. 555 (Nov. 8, 1976), 41 FR 51392 (1976) *reh. den.*, Order No. 555–A (Jan. 6, 1977) 42 FR 3022 (1977), *aff'd sub nom. without opinion, Oglethorpe Electric Membership Corp. v. FERC*, 574 F.2d 63 (D.C. Cir. 1978).

[7] The Commission deemed it appropriate for existing ratepayers to contribute revenues for pollution control equipment to be used by future ratepayers because of "the current generation's commitment to the control of pollution."

[8] Allowance of CWIP associated with fuel conversion facilities recognizes that such construction is necessitated because of the current generation's "consumption of existing stocks of natural resources."

[9] Order No. 555, *supra* note 6, at 13.

[10] *Public Service Company of New Hampshire*, Docket Nos. EL78–15 and ER78–339. In a decision of January 26, 1979, the administrative law judge permitted a utility to include in its rate base CWIP associated with the construction of two nuclear units. However, this case was ultimately settled by the parties before the initial decision reached the Commission for review.

[11] *Montaup Power Company*, Docket No. EL80–8.

[12] *El Paso Electric Company*, Opinion No. 85, Docket Nos. ER77–488 and ER78–520 (Phase I) (May 19, 1980), *reh. den.* Order 85–A (July 17, 1980), appealed to the Fifth Circuit, El Paso Electric Co. v. FERC, No. 80–1763; Louisiana Power and Light Company, Opinion No. 104, Docket No. ER77–533 (Phase II) (December 16, 1980).

[13] *Public Service Company of New Mexico*, Docket Nos. ER78–337 and ER78–338. All but one customer settled with the utility. The initial decision is awaiting Commission review.

[14] *See generally Transcript of Informal Public Conference on Financial Condition of Electric Power Industry*, Docket No. EL81–7–000 (March 6, 1981) [hereinafter cited as *Financial Conference*].

troubled utilities whose financial difficulties are related to large construction programs.

It is the purpose of this rulemaking to scrutinize the issues related to CWIP to relieve financial distress and, after exploring the range of alternative standards which could be applied to the problem, to adopt the rule which best (1) eliminates or reduces extensive and frequently unnecessary litigation on the issue, and (2) clarifies the Commission's policy on this aspect of CWIP relief so that utilities may anticipate Commission response in CWIP cases.[15]

This preamble will explore, first, the rationale of the proposed rule, a mechanical test triggered by low bond ratings. Then in Section IV of this preamble we discuss the major alternatives to the proposed rule. The first set of alternatives would also retain the concept of financial distress but would look to criteria other than bond ratings to determine whether a utility qualifies under this concept. The second set of alternatives would be directed towards the possible effect of including CWIP in rate base on a utility's cost of capital. The final set of alternatives would consider regulatory responses to CWIP which are not directly related to the financial condition of a particular utility. In that section we also request comments suggesting other possible justifications for including CWIP in rate base.

We have not outlined in greater detail the proposed alternative rules due to time constraints. The failure to include more detailed rules for such alternatives should not be viewed as a sign of diminished importance for such alternatives.

III. Rationale for the Proposed Rule

A. The Severe Financial Distress Test—Need for Specificity

The Commission, in Order No. 555, found that it may be desirable to include some CWIP in rate base if a utility could make "a clear showing of severe financial difficulty which cannot be otherwise alleviated without materially increasing the cost of electricity to consumers." [16] The general rationale given by the Commission for granting some CWIP in rate base for cases of severe financial difficulty was that, under some circumstances, it would be the least costly alternative to ensure a utility's financial integrity and to enable it to attract the capital necessary to meet its capital needs. The Commission stated that

> [s]uch a circumstance might arise, for example, where the exigencies of the utility's construction program are such as to reduce its interest coverage to such an extent that additional capital cannot be raised at reasonable rates and that an amount of earnings sufficient to attract capital would require a rate of return on equity substantially in excess of the cost of equity capital to otherwise similar electric utilities. [17]

In other words, utilities may have substantial difficulty in raising capital in an orderly fashion and on reasonable terms to complete large-scale construction programs. Utilities may at times face institutional constraints such as bond indenture coverage provisions (which, for the most part, ignore non-cash AFUDC earnings) so that they are actually precluded from obtaining additional debt funds. And, while utilities may still have access to equity capital markets, this access may be on

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[15] In 1980, the Comptroller General recommended that the Commission undertake a rulemaking to clarify the standards for CWIP in rate base to relieve financial distress. Comptroller General, *Construction Work in Progress Issue Needs Improved Regulatory Response for Utilities and Consumers* (1980) [hereinafter *Comp. Gen. Report*].

[16] Order No. 555, *supra* note 6, at 13.

[17] *Id.*

such unfavorable terms as to force investors to incur capital losses with each new stock issue.

The electric utility industry has ongoing and increasing demands for additional capital. Growth in electricity demand has decreased from the pre-1973 oil embargo level of about 7 percent to about 3 percent in recent years. But even if this trend toward lower growth continues, new capital is needed to replace existing capacity as it approaches obsolescence. In addition, the need to reduce the nation's dependence on foreign oil, as well as the high cost of oil in general, have created demands upon utilities to convert existing oil-fired plants to coal. Finally, utilities have been increasingly required to construct more pollution as well as safety facilities on new and existing plants.[18]

Capital requirements of investor owned electric utilities are projected by Edison Electric Institute to be about $155 billion between 1981–1985. This compares with construction expenditures of about $113 billion during the previous 5–year period ending 1980.[19]

Some perspective on the increasing size of utilities' construction programs can be obtained by examining the relationship between CWIP and net electric plant in service. Whereas CWIP constituted 17 percent of net electric plant in service in 1970 and grew to 28 percent in 1975, CWIP was 40 percent of net electric plant in service in 1979.[20] These statistics are for the total of all Class A & B electric utilities. On a company-by-company basis there is substantial variation.

In addition, there has been a continued deterioration in the electric utility industry's ability to attract the necessary capital to meet its increasing needs. The decline in utilities' access to bond markets in evidenced by the lowering of their bond ratings. Whereas in 1970 a clear majority of electric utilities were rated AA or higher by Standard and Poor's, an overwhelming majority of the same firms are rated no higher than A today.[21] A study by the EEI showed that there were 83 downgradings by Moody's over the last ten years compared with only 16 upgradings.[22] In 1980 alone, 28 electric utilities' bond ratings by Standard and Poor's were lowered while only 3 were raised.[23] Moody's downgraded 14 utilities in 1980 and upgraded only one.[24]

There is also evidence of continued deterioration in the ability of utilities to obtain new common equity capital on reasonable terms. While the average market-to-book ratio of the 100 largest electric utilities rose from .84 in 1975 to slightly in excess of one in 1976 and 1977, it dropped back to .73 in 1980.[25] Given the investor-owned utility industry's heavy dependence on common equity markets (averaging between $3–4 billion annually between 1975 and 1980)[26], existing investors have been forced to bear the effects of continual dilution of their investment.

The worsening of investor confidence in utilities is also evidenced by surveys of investors on their views of the

[18] Under current FERC policies, some CWIP arising from these projected capital needs would be included in rate base. The aforementioned Report of the Comptroller General estimated the extent of FERC's CWIP allowance for the period 1977 through June 1979:

As of December 31, 1978, larger electric utilities had about $5.1 billion of evironmental CWIP, which constituted 12 percent of total CWIP. During test years ending from 1977 through June 1979, FERC allowed pollution control and fuel conversion CWIP in the portion of the rate base under FERC's jurisdiction in 38 rate cases. On an annual basis, the average amount permitted [by the FERC for all utilities] in the rate base was only $89.9 million. *Comp. Gen. Rep., supra* note 15, at 25.

[19] Comments and Exhibits of Edison Electric Institute (EEI), *Financial Conference, supra* note 14.

[20] Department of Energy, Energy Information Agency, *Statistics of Privately Owned Electric Utilities in the United States—1979*: Classes A and B Companies, Table 21 at 28 (1980).

[21] Ann Faber for Standard and Poor's, *Financial Conference, supra* note 14, at 41.

[22] Comments and Exhibits of EEI, *Financial Conference, supra* note 14.

[23] *Financial Conference, supra* note 14, at 41.

[24] *Id.* at 16.

[25] Comments and Exhibits of EEI, *Financial Conference, supra* note 14.

[26] *Id.*

industry. In 1976, 84 percent believed things would improve, 13 percent believed they would stabilize, and 3 percent thought they would deteriorate. From the most recent survey, these percentages are 6 percent improve, 51 percent stabilize and 43 percent deteriorate.[37]

Not all the blame for the utility industry's financial condition can be placed on its capital requirements. A generally ailing economy and high inflation and interest rates have also contributed to its difficulties. However, the electric utility industry has less flexibility than most industries in its construction programs. To meet its obligation to provide service with an adequate level of realiability, the industry must be able to raise capital even under the current difficult conditions. Any significant doubt regarding its ability to do so must be a cause of serious concern.

Given these factors, the small number of filings made under Order No. 555's severe financial distress test indicates that this test should be re-examined. The standards may be too vague and too stringently interpreted and applied. Support for this view can be found in the conclusions of a recent report by the Comptroller General.

Commission regulations which define financial hardship are too vague and general; the Commission should establish a generic rulemaking proceeding to define more specific guidelines or criteria concerning financial hardship.[38]

The proposed rule represents an attempt to respond to such concerns by basing relief on criteria that are more precise and also, potentially at least, less stringent. In addition, in this notice we also invite comments as to whether the Commission's policy on CWIP should be changed in a more fundamental way and directed towards some goal other than the relief of financial distress.

B. The Proposal

The Commission begins with the presumption that CWIP should not be included in rate base, although commentators may wish to address the question whether this presumption is correct. As discussed earlier, this presumption is embodied in the long-established general rule that the capital cost of equipment can be included in rate base only if the equipment is "used and useful" in providing service to the customers for whom the rates are being set. More generally, it reflects a policy on the allocation of costs over time that favors an allocation that matches burdens with benefits. This policy is best served by excluding CWIP from the rate base until the associated plant begins to provide service to ratepayers.

The exclusion of CWIP from rate base also most closely duplicates the operation of an unregulated competitive market. In such a market, the price at which the company can sell the production of its existing facilities is unaffected by the fact that new facilities are under construction. The costs of construction may be included in current costs for accounting purposes and may be financed from current revenues; but in an unregulated market accounting entries do not determine prices, and revenues can be used for reinvestment only by reducing the current return to investors.

The presumption is not irrebuttable, however. It requires only that the inclusion of CWIP in rate base be supported by reasons that are sufficient to counterbalance the Commission's concerns about interperiod equity. In Order No. 555, for example, the Commission found that national goals justified the inclusion of CWIP for investments in pollution control and fuel conversion facilities.

The Commission in the present rulemaking does not intend to revise its existing rules relating to CWIP for these kinds of investments. Instead, this proposal concerns two other possible rationales for including CWIP in rate base. The first, which is reflected in the proposed rule published in this notice, is that inclusion of CWIP may enable a utility to raise capital on reasonable

[37] *Id.* at 28.

[38] *Comp. Gen. Rep.*, *supra* note 15 at iii–iv.

terms where it could not otherwise do so.[29] The second is that inclusion of CWIP may reduce a company's cost of capital. This second possible rationale would logically lead to a rule significantly different from the one published in this notice. As discussed more fully below,[30] we seek comments with respect to both the validity and sufficiency of this second rationale and the kind of rule that it would imply. In addition, the two rationales discussed here may not exhaust the possible justifications for including CWIP in rate base, and we request comments on other possible grounds for granting CWIP relief.

The two rationales discussed here are interrelated. Both assume that, under some circumstances at least, investors do not regard AFUDC as the equivalent of cash income. A company whose earnings include a substantial amount of AFUDC therefore may find it more difficult to raise capital and may also be required to pay a higher price for the capital that it does raise than a company with equal nominal earnings that include a smaller AFUDC component.

The rationales are also interrelated in another way. The first rationale is concerned not only with cases in which a utility cannot raise capital at all but, also, like the second rationale, with cases in which it cannot do so on reasonable terms. The difference between the two rationales, therefore, is one of degree. The first rationale is concerned with cases in which a utility can raise capital only on terms that would be considered unusually onerous. The second rationale is concerned as well with the possibility that a utility can raise capital on commonly accepted terms but could raise it more cheaply if CWIP were included in rate base.

The reasons for drawing this distinction are pragmatic. A rule granting relief only where a utility otherwise could not raise capital on reasonable terms would create a more limited exception to the Commission's general policy on interperiod cost allocation. In addition, it appears to us that it may be possible to base the narrower rule on an informed judgment concerning the effect of CWIP on capital markets. A rule based on the general relationship between CWIP and cost of capital, on the other hand, may have to be supported by a more rigorous empirical study of that relationship.

Under the rationale that the inclusion of CWIP may enable a utility to raise capital on reasonable terms where it could not otherwise do so, the Commission is proposing to specify clear guidelines for implementing its severe financial difficulty test. In the proposed rule that test is restated as a two-pronged test. The first prong would evaluate whether a utility is likely to have difficulty raising capital on reasonable terms. The second prong would evaluate whether this difficulty can reasonably be attributed to the utility's construction program. Having passed these two tests, a utility would be considered presumptively eligible for rate base treatment of at least some of its CWIP. Under the proposed rule, the Commission would, however, retain the power to limit or deny rate base treatment on certain specified grounds.

1. *Indicia of the ability to raise capital (the first prong).* The first question is what variable or variables should be used to determined whether a utility may have difficulty in raising capital on reasonable terms. As proposed, the rule relies solely on the most recent bond ratings given a utility by either of the major rating agencies—Standard and Poor's and Moody's. There are alternatives, such as interest coverage, internal cash flow, and market-to-book

[29] Inclusion of CWIP in rate base may affect a utility's ability to finance construction in two ways. First, it may make it easier for the utility to raise capital. Second, by increasing current cash flow, it may enable the utility to avoid resorting to the financial markets. The second effect might be considered to offer an independent rationale for including CWIP in rate base. However, both effects contribute to the same goal: enabling the utility to finance its ongoing activities.

[30] *See* Section IV B.

ratios. It is our tentative judgment, reflecting in part the limited time available, however, that bond ratings would serve adequately for the purpose at hand, while use of other indicia may present practical difficulties. An interest coverage or internal cash flow test may offer increased complexity and uncertainty but with unknown improvement in results. The additional precision of such a test may be of some value, however, in determining the level of CWIP to be allowed in rate base. Market-to-book ratios, while indicative of the terms upon which common equity can be obtained, are subject to substantial variability over time as the stock market adjusts to general economic conditions. As discussed more fully below, however, we invite comments directed at criteria other than bond ratings to determine if a utility is experiencing difficulty in raising capital on reasonable terms.

Assuming that bond ratings are the appropriate measure, the next question is, what should be the threshold bond rating at which a utility would probably have substantial difficulty in raising capital. Under the proposed rule, a utility would qualify if its first mortgage bond rating at the date of filing were Baa or lower under Moody's rating system or BBB or lower under Standard and Poor's rating system.

There are two reasons for choosing this threshold level. First, there have been times when bonds with such ratings could not, in fact, readily be sold (for example, during 1974 and 1975). Second, if a utility's bond rating dropped below this level, the utility would be likely to encounter substantial difficulties in selling its bonds at almost any time.[31] Since the relief that the Commission could grant under the proposed rule would take some time to have effect, it seems prudent not to wait until the utility's bond rating drops below the BBB/Baa level before granting relief. Conversely, to the extent that the relief is directed at the difficulty a utility may have in raising capital, there does not appear to be any justification for permitting a utility to qualify if its bonds are not rated at the lowest institutional investment grade. The Commission is unaware of any period in the recent past in which A-rated bonds could not be sold, and, in general, it is unlikely that bonds would be quickly down-rated two levels, from A to below BBB/Baa.

2. *CWIP as a source of financial difficulty (the second prong).* If a utility can show it is in financial distress, the next logical question concerns the basis for a finding that CWIP is a significant source of the utility's financial difficulties. The proposed rule bases that determination upon the percentage of the utility's jurisdictional CWIP that is excluded from rate base to the utility's jurisdictional rate base (which would include any CWIP allowed for pollution control and fuel conversion facilities).

The rule focuses on the jurisdictional portion of the utility. An alternative method would be to focus on the entire utility, stating this threshold test in terms of the relationship between total electric utility CWIP excluded from the rate base and total electric utility rate base. The reason for rejecting this latter alternative is that, in most cases, it makes the availability of relief dependent upon the policies followed by state regulatory agencies. If the state that regulates most of the utility's revenues is very generous in putting CWIP in the rate base, the Commission would be able to avoid putting any CWIP in the rate base. Conversely, if the state agency disallows CWIP in the rate base, the Commission would probably be required to put all of the jurisdictional CWIP in the rate base. The proposed rule is intended to set out a policy which would produce reasonable

[31] According to one report on the utility industry's financial problems:

> A credit rating of below Baa/BBB would effectively prohibit many institutional investors—commercial banks, bank-administered trusts, pension funds, insurance companies—from purchasing utility debt. In fact, many institutional investors will purchase no debt below A. These investors historically have comprised 75 percent or more of the market for utility debt.

Exhibit of Booz-Allen & Hamilton, Inc., *Financial Conference, supra* note 14, at I-8.

results if it were followed by both the Commission and the state agencies; it is not intended to compensate for the regulatory policies of state agencies.

The next question concerns the threshold level for the second prong of the test: When should the exclusion of CWIP from rate base be deemed to be a significant cause of the utility's difficulties in attracting capital? The threshold set in the proposed rule (40 percent of jursidictional CWIP to jurisdictional rate base) is based on the industry average ratio of CWIP to net plant in service for 1979, the latest available industry figure.[32] The reasoning behind this choice is that a company's difficulties should not be considered to be due to CWIP if the ratio is not at least as high as the industry average.

There are problems with using this industry average. There is the technical problem that the average is based on total electric CWIP of class A and B electric utilities. It does not take account of the fact that some CWIP included in the industry statistics is already included in rate base; and for purposes of the rule proposed here, the 40 percent figure is thus too high. There is also the more fundamental problem that a threshold based on a current industry average links the rule to the state of the industry at one point in time. The industry average has increased from 17 percent in 1970 to 40 percent in 1979. The link to the industry average thus suggests that we might have formulated a more generous rule in 1970, when the industry was relatively healthy, than in 1981, when the industry is experiencing serious financial problems.

Thus, while the proposed rule uses a 40 percent ratio, the Commission is skeptical of the basis for that number and requests that comments be directed toward providing a more rational basis on both theoretical and empirical grounds.

3. *Amount of CWIP to be allowed.* a. *The basic determination.* Once a determination is made that a utility qualifies for an allowance of some CWIP in rate base, the next issue is the extent of CWIP relief.

The proposed rule would permit the amount of CWIP in rate base necessary to bring the utility's ratio of CWIP not included in rate base to rate base to the so-called threshold level indicated by the second prong of the severe financial difficulty test. Rate base here includes any CWIP that the Commission permits to be included in rate base, whether for pollution control or fuel conversion or for financial distress.

For example, suppose that a 100 percent jurisdictional utility has the necessary bond rating (that is, it passes the first prong of the test). It also has net electric plant in service of $110 million and has pollution control CWIP of $10 million that is already included in rate base. Its total rate base is therefore $120 million. Also assume that other CWIP, not yet included in rate base, is assumed to average $76 million over the test period. Since the latter figure is more than 40 percent of rate base, the company also meets the second prong of the test. The company would then be presumptively entitled to include in its rate base an additional amount of CWIP sufficient to reduce the amount of CWIP outside of the rate base to 40 percent of rate base. The additional amount to be included would be $20 million, giving the company a rate base of $140 million and leaving $56 million (40 percent of $140 million) outside of the rate base.

The approach taken in the proposed rule follows from the severe financial difficulty premise: CWIP is allowed in rate base only to the extent necessary to eliminate it as a major source of financial difficulty.

There are alternatives to this approach. One alternative would be to allow the utility to include in rate base

[32] *See supra* footnotes 19 and 20 and accompanying text.

only some percentage of the amount that would be necessary to bring the ratio of CWIP outside of rate base to rate base down to the threshold, perhaps thereby providing some incentive to the utility to minimize CWIP. On the other hand, if the utility passed the qualifying tests, it might be allowed to include enough CWIP in rate base to bring the ratio below the threshold; this alternative might be viewed as creating a "safety zone" below the threshold, so that the utility would be less likely to need additional relief in the near future.

b. *Commission adjustments.* The proposed rule contains a provision to permit the Commission to reduce the amount of CWIP that might be added to rate base on a case-by-case basis. This provision contains four matters the Commission may consider in this regard: (1) substantial short-run effects on electric rates to consumers; (2) price-squeeze effects; (3) considerations of managerial negligence or wrongdoing; and (4) considerations as to the reasonableness of the construction program.

With respect to short-run impact on consumers, the Commission proposes to retain the right to limit the amount of CWIP allowed in rate base when the amounts allowed under the rule would raise rates so substantially as to cause undue hardships upon ratepayers. It is also proposed that a preliminary determination be made by the Commission prior to permitting rates to go into effect subject to refund.

As to price squeeze considerations, the Commission believes that it is not prevented from instituting a CWIP in rate base policy although the possibility exists that the use of CWIP in rate base may be a contributing factor to undue price discrimination in a particular case. Many factors can contribute to a Commission finding of price squeeze and undue discrimination, including differences between federal and state commission policies. These factors will be explored by the commission in each case in which the price squeeze issue is raised. The Commisson does intend to retain the flexibility to deny CWIP in rate base or modify other cost of service methods as possible remedies after a finding of undue discrimination. Moreover, the Commission will not, in this rule, limit the denial of CWIP in rate base to those circumstances in which the state commission does not allow CWIP in rate base and this conflict is a contributing factor to the undue discrimination.

In addition, the Commission reserves the right to disallow the inclusion of CWIP in rate base if it can be demonstrated that the utility's financial woes are attributable to management negligence or wrongdoing, or if it can be shown that the utility's construction program is not needed to meet future demand. While we expect that these showings will be exceedingly difficult to make, we believe they are relevant areas of inquiry in rate proceedings in which CWIP in rate base is an issue.

4. *Duration of inclusion of CWIP in rate base.* The decision by the Commission to permit inclusion of an amount of CWIP in rate base on account of severe financial difficulty shall only be effective for the period that the rates examined in the proceeding remain effective. In the next rate proceeding the rate applicant will not be able to include any CWIP in rate base if its bond rating has improved or if the new ratio of jurisdictional CWIP to jurisdictional rate base does not exceed the threshold.

5. *Allowance of CWIP subject to refund.* The proposed rule incorporates a change from Order No. 555 to permit CWIP in rate base in rate filings subject to refund. Under the proposed rule, the necessary showing of severe financial difficulty is straightforward and based on easily verifiable data. Further, since the object is to aid financially distressed utilities, it is counterproductive to withhold relief until the end of what may be a lengthy rate case.

This change from Order No. 555 is also based on the Commission's view that there is no persuasive reason to require inconsistent effective date treatment for inclusion of CWIP for pollution control and fuel conversion

facilities and for inclusion of CWIP on a severe financial difficulty basis.

The ratepayers will be entitled to refunds of all amounts collected that are attributable to inclusion of CWIP in rate base in the event that the Commission ultimately determines that such inclusion is unjust, unreasonable, unduly discriminatory or preferential. This procedure will, in general, afford ratepayers adequate protection for the interim period. Furthermore, the Commission proposes to retain the flexibility to reduce the amount of CWIP allowed under the rule for rates put into effect subject to refund if the resulting rate increase would be substantial.

IV. Alternatives to the Proposed Rule

A. Alternative Criteria for Determining Severe Financial Difficulty

The proposed rule uses bond ratings as a criterion for determining whether a utility is in severe financial difficulty. Other, possibly more refined, measures of severe financial difficulty are also candidates for inclusion in the final rule. Two such measures are "quality of earnings" and interest coverage ratios.

By "quality of earnings" we mean the relationship of a utility's AFUDC to its net income. It is commonly said that the quality of a utility's earnings is inversely related to the ratio of AFUDC to net income and that a utility will find it easier (or less costly) to raise capital if its earnings are of a higher quality.

By "interest coverage ratio" we mean the ratio of a utility's pre-tax income—frequently, excluding AFUDC—to its long-term interest obligations. The interest coverage ratio is one indication of the likelihood that the utility will be able to meet its interest obligations, and trust indentures frequently forbid a utility to sell additional bonds if the coverage ratio would fall below a certain level, usually 2.0.

The use of such measures to determine eligibility for the inclusion of CWIP in rate base presumes that they are reasonable indications of a utility's ability to raise capital on reasonable terms and that they are likely to be affected by the inclusion of CWIP in rate base. Although the second relationship apparently is clear, we seek comments regarding both of these presumed relationships. In addition, two other issues are raised by the possible use of these measures.

First, a rule that defines eligibility for inclusion of CWIP in terms of these concepts would be substantially different from the proposed rule. The problem is to formulate a rule that can deal reasonably with the range of specific company situations to which it is likely to be applied without making the rule either excessively vague or unmanageably complex. We therefore seek comments regarding the formulation of a rule based on quality of earnings, interest coverage ratios, or other possible measures of a utility's financial condition.

Second, we also seek comments as to whether a rule based on such measures will result in additional complexity, and, if so, offers advantages that justify this additional complexity. Further, we seek comments as to whether such a rule should be used in addition to or in place of one based on bond ratings.

B. CWIP and the Cost of Capital

The proposed rule discussed in section III necessarily assumes that inclusion of CWIP in rate base may reduce the cost of capital to companies that are experiencing financial difficulty; otherwise, except for those cases in which increased cash flow was itself directly responsive to a utility's financial difficulties, relief would be limited to those companies that found it literally impossible to raise capital. There is also some support for the view that inclusion of CWIP may reduce the cost of capital for companies in general. This view implies that the goal of interperiod equity may conflict with the goal of minimizing the rates to all consumers as a group, including both present and future consumers. We seek comments to assist us in determining whether such a conflict does exist, and if so, what implications it may have for inclusion of CWIP in rate base.

To provide a framework for these comments, we will briefly set out what appears to us to be the analytical structure of the inquiry. This structure consists of four issues. The first concerns the existence and form of the relationship between inclusion of CWIP in rate base and the cost of capital. The second concerns the proper measure of the effect of a CWIP policy on rates for both present and future consumers where the effect is not evenly distributed over time. The third concerns the evaluation of the trade-off, if any, between minimizing aggregate cost to all consumers and achieving interperiod equity. The last issue concerns the form of the rule implied by this analysis.

1. *The relationship between CWIP and cost of capital.* We are aware of some studies dealing with the relationship between inclusion of CWIP in rate base and cost of capital.[33] It does not now appear to us, however, that these studies provide an adequate basis for a rule premised on that relationship. We therefore seek comments that provide us with, or refer us to, additional studies as well as comments on the studies here cited.

We wish to emphasize that on this issue anecdotal evidence is unlikely to be useful. Precision may be an illusory goal. It is, however, possible to set out explicitly the assumptions and methods on which conclusions are based. Unless this is done, it is difficult to place any reliance on the conclusions themselves.

2. *The measurement of aggregate effect on consumer rates.* It is conceivable that, in some cases, the inclusion of CWIP in rate base will reduce the cost of capital so much that even current rates will be lower. But we would expect such cases to be rare. In general, even if the inclusion of CWIP in rate base does reduce the cost of capital, the immediate effect probably will be to increase current rates. Its inclusion will also, of course, decrease future rates. To determine the aggregate impact on present and future consumers, it is necessary to take account of both the immediate increase and the future decrease, and, for this purpose, a discount rate is required. We therefore seek comments on the appropriate discount rate for measuring the aggregate impact on utility customers of including CWIP.

One possibility is to use the utility's cost of capital as the discount rate for consumers.[34] If this alternative is selected, inclusion of CWIP in rate base will reduce the aggregate cost to present and future consumers if, and only if, its inclusion reduces the company's cost of capital. It is not clear, however, that this alternative is the proper one. The persons ultimately affected by our policy on CWIP will be the retail customers to whom the rate increases and reductions are passed through. It appears unrealistic to suppose that these customers in general have the same opportunities for borrowing and investment as the utilities that are subject to our jurisdiction. Moreover, to the extend that the electricity is consumed for noncommercial purposes, the future rate reductions resulting from inclusion of CWIP in rate base in effect constitute tax-free income while the cost of capital to the utility is substantially affected by taxation.

It is unclear to us at this time whether the difference, if any, between the utility's cost of capital and the appropriate discount rate for consumers can be quantified. Even if it cannot, however, we seek comments as to

[33] Arthur Anderson and Co., *Study of the Treatment of Construction Work in Progress and Tax-Timing Differences for Rate-Making Purposes in the Electric Utility Industry* (1977); Comtois, *Construction Work in Progress in the Rate Base: A Benefit to the Consumer* 19 Pub. Util. Fort. (May 8, 1980); Fitzpatrick and Stitzel, *Capitalization of AFUDC: The Impact on Earnings Quality* 18 Pub. Util. Fort. (Jan. 19, 1978); Lerner and Breen, *The Changing Significance of AFUDC for Public Utilities* 17 Pub. Util. Fort. (Jan. 1, 1981); Trout, *The Regulatory Factor and Electric Utility Common Stock Investment Valves* 28 Pub. Util. Fort. (Nov. 11, 1979); Trout, *A Rationale for Prefering CWIP in the Rate Base* 22 Pub. Util. Fort. (May 10, 1979).

[34] In this connection, it should be emphasized that the cost of capital to the utility might be different under a policy of CWIP in rate base.

whether use of the utility's cost of capital for this purpose is likely to bias our analysis.

3. *The tradeoff between aggregate consumer cost and interperiod equity.* If we conclude that aggregate consumer cost, however measured, would be reduced by the inclusion of CWIP in rate base, we then confront the conflict between goals that was set out earlier: minimization of aggregate cost will make the interperiod distribution of costs somewhat less fair, but unconstrained pursuit of the goal of interperiod equity will increase aggregate cost to all consumers, both present and future. Unless one of these conflicting goals is to be regarded as totally subordinate to the other, we must strike a balance based on our concept of the public interest for which we are responsible. It is unlikely that any analytical technique or simple rule can determine that balance. We do, however, seek comments that may assist us in approaching and defining this issue.

4. *The form of the rule.* The question of the form of the rule is reached if we conclude that the inclusion of CWIP in rate base will reduce aggregate cost to consumers, and that this reduction in aggregate cost justifies some sacrifice of interperiod equity. If we do reach this point in our analysis, we must then determine how our policy conclusions should be embodied in the rule relating to allow CWIP in rate base. Such a rule might resemble the one published here, but with the omission of any requirement based on bond ratings. The rule might, in other words, substitute a "single-pronged" test for the double-pronged test used in the proposed rule. Thus, companies would presumptively qualify for relief if CWIP outside of rate base exceeded a certain percentage of the rate base, and this threshold percentage would also determine the measure of relief. The threshold percentage could be based on the relationbship between inclusion of CWIP and cost of capital; it is possible, for example, that the exclusion of small amounts of CWIP from rate base does not significantly affect the cost of capital. Alternatively, the threshold might reflect the tradeoff between the goals of minimizing aggregate cost and interperiod equity.

As the preceding remarks suggest, the form of the rule will be determined in part by the nature of the analysis justifying it, and persons commenting on the form of such a rule should indicate clearly the analytical basis for their comments.

C. Other Alternatives

The proposed rule is the Commission's preliminary attempt to provide a practicable framework to handle the CWIP issue as it relates to its inclusion in rate base on the basis of financial difficulty. We invite comments, not only on the proposed rule, but also on the following alternative proposals that the Commission believes also have merit. We have decided not to propose these alternatives due to difficulty in drafting in the limited time available to us. However, the fact that these alternatives are not embodied in a proposed rule does not signify that we will not give serious consideration to them.

This is not intended to be an exhaustive list. Commenters are invited to submit other proposals and to support them with empirical data or with other substantial evidence.

1. *Maintain status quo:* For the reasons previously discussed, we believe that the policy statement embodied in Order No. 555, should be modified to provide specific guidelines to rate applicants and to avoid protracted litigation.

2. *Allowing a straight percentage of CWIP in rate base regardless of a utility's financial condition.* This alternative has the advantage of eliminating controversy over the appropriate standard for determining financial difficulty. However, it would require the Commission to depart significantly from its present policy by permitting CWIP in the rate base of utilities regardless of their financial health.

3. *Allow CWIP associated with particular plants to go into rate base a specified period of time prior to their becoming "used and useful."* This is a procedure followed by several state commissions. Presumably, this approach would permit inclusion of CWIP at a time when it is reasonably certain that a plant will be completed. Again, this option would eliminate the need for a financial difficulty test and would benefit healthy as well as ailing utilities.

4. *Allow CWIP in rate base to the extent that a utility's predominant regulatory authority permits it.* The principal advantage to this approach is to lessen the possiblity that price squeeze will result from inclusion of CWIP in rate base. It also recognizes the predominant role of the state commission in determining the financial condition of the utility. However, this alternative may not enable this Commission to assist utilities in severe financial difficulty, may provide healthy utilities with aid they do not need, and would subordinate this Commission's rate-setting responsibilities to those of the state commission concerned.

5. *Require contributions in aid of construction in lieu of CWIP.* Viewed in another light, inclusion of CWIP in rate base can be seen as a customer loan to a utility in financial difficulty. If this customer contribution is not considered taxable income to utilities by the Internal Revenue Service, required contributions in aid of construction could be the least costly way for the customers to provide aid to ailing utilities. However, the Commission believes it is unlikely that the IRS would find such contributions to be non-taxable income.

V. Summary of the Proposed Rule

The current Commission rule on CWIP (§ 2.16(b)) provides that the Commission will grant CWIP in rate base for certain types of pollution control and fuel conversion facilities and to alleviate "severe financial difficulty." CWIP for financial difficulty under the present rule is permitted only if a utility has shown severe financial difficulty.

The current CWIP rule is codified in § 2.16 of the Commission's regulations. This section is in Part 2, which is intended to contain the Commission's statements of policy. Since the CWIP provisions are substantive regulations pertaining to the filing of rate schedules by electric utilities, the provisions more properly belong in Part 35 of the Commission regulations under the Federal Power Act. Accordingly, the proposed rule would remove § 2.16 and add a new Subpart D to Part 35, containing the CWIP provisions.

Substantively, the proposal would make no changes to the current rules regarding the inclusion of pollution control and fuel conversion facilities.[35] As discussed below, the proposal would refine the criteria under which the Commission may grant CWIP inclusion in rate base to relieve severe financial difficulty.

The proposed rule contains four sections: definitions, general provisions for the inclusion of CWIP, the special rules for severe financial difficulty, and a refund rule.

The defined terms in proposed § 35.60 include: "Construction work in

[35] The proposed changes regarding pollution control and fuel conversion facilities are editorial and are limited to moving portions of the current § 2.16(a) to place the definition of pollution control and fuel conversion facilities in a definitional paragraph with other definitions and making minor revisions for grammatical accuracy and stylistic consistency.

progress,"[36] "jurisdictional CWIP,"[37] "rate base,"[38] "jurisdictional rate base,"[39] "pollution control facility" and "fuel conversion facility conversion facility."[40]

The general CWIP provisions are contained in proposed § 35.61. Paragraph (a) of that section declares that a utility seeking the inclusion of CWIP in rate base for any purpose must do so by filing a rate schedule. Paragraph (b) provides that the Commission will permit the inclusion of CWIP for pollution control and fuel conversion facilities. Paragraph (c) states that the Commission may allow the inclusion of CWIP to relieve the severe financial difficulty of a utility. Finally, paragraph (d) sets forth the accounting requirements that a utility receiving rate base treatment of CWIP must discontinue the capitalization of AFUDC and must establish procedures to ensure that wholesale customers will not be charged for the corresponding AFUDC capitalized as a result of different accounting or ratemaking treatment by another regulatory agency.[41]

The proposed special rules for the inclusion of CWIP to relieve severe financial difficulty establish a two-pronged test for a utility to qualify for this relief (§ 35.62(a)). First, the utility must demonstrate that it suffers from serious financial problems. The proposed rule requires a showing that its current first mortgage bond rating is low, *i.e.*, a rating of Baa of lower under Moody's or BBB or lower under Standard & Poor's, (§ 35.62(a)(1)).

If the utility can show the requisite bond rating, it must then demonstrate that that its jurisdictional CWIP excluded from rate base is at least 40 percent of its jurisdictional rate base (§ 35.62(a)(2)). If the utility meets this standard, it would generally be permitted to include in rate base an additional amount of CWIP sufficient to reduce the amount of jurisdictional CWIP excluded from rate base to 40 percent of jurisdictional rate base. Jurisdictional rate base includes, for this purpose, CWIP included in rate base under § 35.61(b) and (c).[42]

To add flexibility to the mechanical test, if it proposed that the Commission retain the discretion to reduce the amount of CWIP to be included or to phase it in over time. The Commission would exercise this discretion by taking into account:

- whether inclusion of the mechanically determined amount of CWIP in rate base would have a seriously adverse effect on short-term consumer electricity prices,
- findings that such inclusion would result in a price squeeze,
- findings, that the financial condition of the utility was caused either by managerial negligence or wrongdoing.

[36] "CWIP" is defined by reference to the Uniform Systems of Accounts for Public Utilities and Licenses Subject to Accounts 107 (construction work in progress) and 120.1 (nuclear fuel in process of refinement, conversion, enrichment and fabrication); both accounts are eligible for AFUDC treatment.

[37] "Jurisdictional CWIP" is a formula for deriving that portion of a utility's construction work in progress which can be allocated to its jurisdictional customers for purposes of this section.

[38] "Rate base" is defined as the rate base as filed under § 35.13 (electric rate schedule filing requirements).

[39] "Jurisdictional rate base" is that portion of a utility's rate base which can be appropriately allocated to its jurisdictional customers; this is done in the ensuing rate case.

[40] The definitions of pollution control and fuel conversion facilities are substantially unchanged from current § 2.16(a).

[41] The provisions of paragraph (d) are substantially the same as those in current § 2.16(c).

[42] Under current § 2.16(b) a utility is required to show by "clean and convincing evidence," that it suffers from severe financial difficulty which cannot be otherwise alleviated without materially increasing the cost of electricity to consumers. Order No. 555, *supra* note 6, at 13. Under the proposed mechanical test which turns upon empirical data, it no longer seems necessary or appropriate to retain such a burden of proof. Therefore, the Commission proposes to dispense with the need for "clear and convincing evidence" in CWIP cases.

- findings, that the construction programs were not necessary to meet reasonable projections of future requirements. (§ 35.62(b)(2))

The proposed special rules for financial difficulty also contemplate that any CWIP permitted would remain in rate base only as long as the rates examined in the proceeding are effective. (§ 35.62(c))

Finally, the proposed rule changes the refund provisions of current § 2.16 relating to severe financial distress. Under the current rule, CWIP for severe financial distress can be collected only after the conclusion of the rate case. The proposed rule (§ 35.63) would allow a utility to collect this CWIP subject to refund. However, if it appears to the Commission that the inclusion of CWIP in rate base would have a seriously adverse effect on short-term electric rates, when it sets the rate for hearing under the proposed rule the Commission may limit the amount of CWIP which the utility is able to collect subject to refund.

VI. Certification of No Significant Impact on a Substantial Number of Small Entities

The Regulatory Flexibility Act[43] requires certain statements and analyses of proposed rules if compliance with the proposed rules will have "a significant impact on a substantial number of small entities." Pursuant to Section 605(a) of the Regulatory Flexibility Act, the Commission finds that the provisions of the Act do not apply to this rulemaking. Since nearly all of the jurisdictional utilities which must comply with the rule proposed here are too large to be considered "small entities,"[44] the Act is not applicable.

Further, since the utilities regulated by the Commission hold exclusive selling rights within their service areas and are presumed to be natural monopolies, they dominate their respective fields of operation and, thus, cannot be considered to be "small entities" as that term is defined in the Act.[45] Consequently, this rulemaking has no significant impact on a substantial number of entities.

VII. Public Comment Procedures and Additional Questions

A. Procedures

Interested persons are invited to submit written comments on the proposed rule to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should refer to Docket No. 81-38, on the outside of the envelope and on all documents submitted to the Commission. To ensure proper consideration of their comments, it is essential that persons submitting comments identify specifically the section and paragraph of the preamble or the rule which they are addressing. When persons submitting comments urge an approach different from the one proposed here, a specific alternative provision with appropriate legal or empirical support should be submitted. Furteen copies should be submitted with the original. All comments received by the Commission by September 23, 1981, will be considered prior to the promulgation of the final rule. Reply comments received by the Commission

[43] 5 U.S.C. 601-612 (Supp. 1981).

[44] Currently, 211 entities have rate schedules on file with the Commission. Of these, 184 are Class A or B utilities (having annual electric operating revenues of more than $2,500,000 or $1,000,000 respectively), 20 are other investor-owned utilities, 3 are industrially-owned, two are cooperatives, one is a state agency, and one is a non-profit organization. Thus, only 27 regulated entities complying with this rule have annual electric operating revenues of less than $1,000,000.

[45] Section 601(6) of the Act defines a "small entity" as a small business, a small not-for-profit enterprise, or a small governmental jurisdiction. A "small business" is defined, by reference of Section 3 of the Small Business Act, as an enterprise which is "independently owned and operates and which is not dominant in its field of operation." 15 U.S.C. 632(a) (Supp. 1981).

by October 23, 1981, will be considered prior to the promulgation of the final rule. Reply comments should be so identified and conform to all requirements applicable to initial written comments. Copies of the written comments may be obtained from the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357–8055. Comments are available for public inspection during business hours at the same location.

B. Additional Questions

In addition to the issues raised directly by the preamble, the Commission wishes to solicit comments on the following related questions. Persons addressing these questions are requested, in their comments, to refer to these by number.

1. Is a "mechanical" approach, as proposed, appropriate for determining whether a utility will be permitted to include CWIP in its rate base, and, if so, the amount of CWIP to be permitted?

2. Should a mechanical rule's focus be, as proposed, a utility's ability to raise capital? (An alternative focus would be the effect of including CWIP on the utility's cost of capital.)

3. If a mechanical rule is used that focuses on a utility's ability to raise capital, what is the most appropriate measure of this ability:

- first mortgage bond ratings, as proposed in the draft rule;
- internal cash flow;
- interest coverage;
- AFUDC to net income ratio;
- market-to-book ratio; or
- some combination of these or other indicators?

4. What is the appropriate measure for determining if CWIP is a major cause of a utility's financial problems:

- ratio of CWIP to rate base; or
- ratio of CWIP to net electric plant in service; or
- some other measure?

5. Is there a general connection between a utility's financial condition and the amount of CWIP included in its rate base? If so, how should this relationship be reflected in the Commission's rule? (In the proposed rule, the assumed relationship is reflected in the requirement that jurisdictional CWIP excluded from the rate base be at least 40 percent of the jurisdictional rate base.)

6. Is the inclusion of CWIP in the rate base more appropriately a tool for dealing with short-term cash flow problems than for dealing with the utility's cost of capital or lack of access to capital markets?

7. What is the appropriate basis for determining the amount of CWIP that should be allowed in the rate base to alleviate demonstrated financial difficulty?

8. In considering the questions of whether CWIP is a cause of financial distress and what relief should be granted, should the Commission look to the condition of the whole company or only to the jurisdictional portion of the company?

9. If the treatment of CWIP by state regulatory agencies is likely to affect the utility's financial condition, should the Commission's rule be constructed to analyze the question of including CWIP independent of this effect? How could this be done?

10. Should "jurisdictional CWIP" be determined, as proposed, as a proportion of the utility's total CWIP, or should the determination be based on the specific nature or intended use of the facilities that are under construction?

11. Should the Commission retain discretion to limit the amount of CWIP included in the rate base, or to phase CWIP into the rate base over time? If so, what factors should be considered in the exercise of this discretion? Should it consider factors in addition to those listed in § 35.62(b)(2)?

12. Should a utility be permitted to collect CWIP subject to refund? If so, should the Commission retain the authority to limit the amount of CWIP that may be allowed? If so, under what circumstances should the Commission be able to exercise this authority?

13. Should CWIP relief be limited to the period in which the rates examined remain effective? If it is not so limited, should it be limited in some other way? For example, should CWIP relief expire after a specified period of time?

14. Would the Commission's adoption of a rule permitting the inclusion of additional CWIP in a utility's rate base require the amendment of any other Commission rules? If so, for what reasons would the changes be needed, and what would be an appropriate amendment?

15. Is there a better way to alleviate a utility's cash flow problems than by including CWIP in rate base?

16. With respect to the reasons for which the Commission may reduce the amount of CWIP allowed in rate base to relieve severe financial distress, how should the Commission evaluate the effects of CWIP's inclusion on short-term consumer electricity prices? What are the limits of the Commission's ability to consider such effects?

(Administrative Procedure Act, 5 U.S.C. 551–557; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Federal Power Act. 16 U.S.C. 791–828c, as amended; Exec. Order No. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission proposes to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 2—GENERAL POLICY AND INTERPRETATIONS

§ 2.16 [Removed]

1. Section 2.16 is removed in its entirety.

2. Part 35 is amended in the table of contents by adding a new Subpart D to read as follows:

PART 35—FILING OF RATE SCHEDULES

Subpart D—Inclusion of Construction Work in Progress in Rate Base of Electric Utilities

Sec.

35.60 Definitions.

35.61 General rules.

35.62 Special rules for severe financial difficulty.

35.63 Refund rule.

Authority: Administrative Procedures Act, 5 U.S.C. 551–557; Department of Energy Organization Act, 42 U.S.C. 7101 et seq.; Federal Power Act, 16 U.S.C. 791–828c, as amended; E.O. 12009, 3 CFR page 142 (1978).

3. Part 35 is amended by adding a new subpart to the end thereof to read as follows:

Subpart D—Inclusion of Construction Work in Progress in Rate Base of Electric Utilities

§ 35.60 Definitions.

For purposes of this subpart:

(a) "Construction work in progress" (CWIP) means the amounts properly included in Accounts 107 (construction work in progress) and 120.1 (nuclear fuel in process of refinement, conversion, enrichment and fabrication) of the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act (Class A and Class B).

(b) "Jurisdictional CWIP" means the utility's total CWIP multiplied by the ratio of the utility's jurisdictional rate base to its total rate base (total company).

(c) "Rate base," except in § 35.62(b) of this subpart, means the rate base as shown by the filing party under § 35.12 or 35.13 of this part.

(d) "Jurisdictional rate base" means that portion of a utility's rate base which can be appropriately allocated to the utility's jurisdictional customers.

(e) "Pollution control facility" means an identifiable structure or portions of a structure which is designed to reduce the amount of pollution produced by the underlying power facility, except that a facility which lessens pollution by substituting a different method of generation and a facility for generation of additional power necessitated by the operation of pollution control facilities, shall not be included in this definition. In determining which facilities qualify

as pollution control facilities, the Commission will consider:

(1) whether such facility falls within the definition of "a new identifiable treatment facility which is * * * to abate or control water or atmospheric pollution or contamination by removing, altering, disposing or storing of pollutants, contaminants, wastes or heat" under 26 U.S.C. 169.

(2) whether such facility has been certified by a local, state, or federal agency as being in conformity with, or required by, a program of pollution control;

(3) whether such facility falls within the following items (from sections 4A through 4D of Environmental Protection Facilities, FERC Form 1):

(i) Air pollution control facilities:

(A) Scrubbers, precipitators, tall smokestacks, etc.,

(B) Changes necessary to accommodate use of environmentally clean fuels such as low ash or low sulfur fuels including storage and handling equipment,

(C) Monitoring equipment,

(D) Other;

(ii) Water pollution control facilities:

(A) Cooling towers, ponds, piping, pumps,

(B) Waste water treatment equipment,

(C) Sanitary waste disposal equipment,

(D) Oil interceptors,

(E) Sediment control facilities,

(F) Monitoring equipment,

(G) Other;

(iii) Solid waste disposal costs:

(A) Ash handling and disposal equipment,

(B) Land,

(C) Settling ponds,

(D) Other;

(iv) Noise abatement equipment:

(A) Structures,

(B) Mufflers,

(C) Monitoring equipment,

(D) Other; as well as

(4) any other relevant evidence tending to show that such facilities are for pollution control.

(f) "Fuel conversion facility" means a facility which enables a plant which previously burned natural gas to convert to the use of other fuels, and a facility which enables an oil-burning plant to convert to fuels other than natural gas, including those which alter internal plant workings, such as oil or coal burners, soot blowers, bottom ash removal systems, and concomitant air pollution control facilities, as well as a facility needed for receiving and storing the fuel to which the plant is being converted, which would not be necessary if the plant continued to burn gas, or oil, as originally designed.

§ 35.61 General rules.

(a) *Procedures.* A utility shall seek the inclusion of CWIP in rate base under this subpart by filing a rate schedule in accordance with 18 CFR Part 35.

(b) *Pollution control and fuel conversion facilities.*

The Commission will allow the inclusion of CWIP in rate base for pollution control facilities and fuel conversation facilities.

(c) *Severe financial difficulty.* The Commission may allow the inclusion of CWIP in rate base to relieve severe financial difficulty.

(d) *Accounting requirements.*

(1) A utility which seeks the inclusion of CWIP in rate base under this subpart must show that it will discontinue the capitalization of allowance for funds used during construction (AFUDC) on such amounts of CWIP as may be permitted by this Commission to be included in jurisdictional rate base.

(2) A utility which seeks inclusion of CWIP in rate base under this subpart shall also propose accounting procedures to ensure that wholesale customers will not subsequently be charged for any corresponding AFUDC capitalized as a result of different accounting and ratemaking treatment accorded CWIP by a state commission or other regulatory authority.

§ 35.62 Special rules for severe financial difficulty.

(a) *Qualification standards.* To qualify for the inclusion of CWIP under § 35.61(c) of this subpart, an electric utility must demonstrate,

(1) that the first mortgage bond rating of the utility at the date of filing is Baa or lower under Moody's Bond Ratings or BBB or lower under Standard & Poor's Bond Ratings; and

(2) that the dollar amount of the utility's jurisdictional CWIP minus the dollar amount of CWIP included in its jurisdictional rate base under § 35.61(b) of this subpart is at least 40 percent of the dollar amount of its net jurisdictional rate base. Jurisdictional rate base, for purposes of this paragraph, includes the dollar amount of CWIP included in its jurisdictional rate base under § 35.61(b) of this subpart but does not include the dollar amount of the utility's jurisdictional CWIP sought under § 35.61(c) of this subpart.

(b) *Amount of CWIP included.*

(1)(i) Subject to the provisions of paragraph (b)(2) of this section, if an electric utility qualifies for the inclusion of CWIP in its rate base under paragraph (a) of this section, it may include in its jurisdictional rate base no more than an amount of CWIP such that the jurisdictional CWIP not included in jurisdictional rate base is 40 percent of the jurisdictional rate base.

Example: Section 35.62(b) is intended to allow a qualifying utility to reduce the amount of jurisdictional CWIP outside of its jurisdictional rate base to the threshold level established by § 35.62(a)(2). At that level, the amount of jurisdictional CWIP outside the rate base is 40 percent of the jurisdictional rate base. An equivalent way to describe this level is to say that the jurisdictional rate base is then equal to 100/140 or approximately 71 percent of total jurisdictional investment (jurisdictional rate base plus jurisdictional CWIP not included in the rate base). Thus, assume that a qualifying utility's jurisdictional rate base prior to receiving any relief under § 35.62(b) is $120 million, including $10 million for pollution control facilities included in the rate base under § 35.61(b). It also has $76 million in jurisdictional CWIP that is not included in the jurisdictional rate base. On these facts the utility presumptively is entitled to include an additional $20 million of CWIP in its rate base under § 35.62(b). Adding this amount to the rate base would give it a total jurisdictional rate base of $140 million. This total jurisdictional rate base is 100/140 of total jurisdictional investment. Total jurisdictional investment ($196 million) × 100/140 = $140 million. The same result can be expressed in terms of the relationship of jurisdictional SWIP outside the rate base to jurisdictional rate base:

Jurisdictional rate base ($140 million) × 40% = jurisdictional CWIP outside the rate base ($56 million).

(ii) "Rate Base," for purposes of paragraph (b)(1), means the rate base included in the cost of service approved by the Commission at the conclusion of the rate proceeding.

(2) In considering the treatment of CWIP in a utility's rate base under this paragraph, the Commission may reduce the amount of CWIP to be included in a utility's rate base, or the Commission may require the allowed amount of CWIP to be included in a utility's rate base phased in over a period of time to be determined by the Commission, for any or all of the following reasons:

(i) the adverse effect on short-term consumer electric prices of CWIP in rate base;

(ii) the extent to which CWIP in rate base may create price discrimination between a utility's wholesale and retail rates with an anticompetitive effect;

(iii) the extent to which the utility's financial difficulty is attributable to management negligence or wrongdoing; and

(iv) the extent to which the utility's construction program is not needed to meet reasonable projections of future capacity requirements.

(c) *Time limitations.*

A utility permitted to include CWIP in rate base under this section shall be permitted to include such CWIP in rate base only for the period that the rates examined in the proceeding are effective.

§ 35.63 Refund rule.

(a) An electric utility which appears to qualify for CWIP under § 35.62(a) of this subpart may collect amounts related to

CWIP subject to suspension and to refund, during the pendency of a final Commission determination; except that, when a utility seeks the inclusion of CWIP in its rate base to relieve severe financial distress, the Commission may limit the amount of CWIP which may be collected subject to refund for the reason set forth in § 35.62(b)(2)(i) of this subpart.

(b) Subject to the provisions of paragraph (a) of this section, an electric utility may include CWIP as part of its jurisdictional rate base for financial distress in rates subject to suspension and refund, no more than an amount of CWIP such that the jurisdictional CWIP not included in jurisdictional rate base is 40 percent of the jurisdictional rate base.

¶ 32,148 Fees Relating to Freedom of Information Act Requests

46 F. R. 39846 (August 5, 1981).

18 C F R Part 3 and 375

[Docket No. RM81-40]

Fees Relating to Freedom of Information Act Requests

July 31, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission is amending its regulations relating to Freedom of Information Act request by adding a provision to establish fees for search and duplication services performed by Commission staff pursuant too Freedom of Information Act requests 5 U.S.C. 552. Also, the Commission is adding a provision which delegates to the Director of the Commission's Division of Public Information, the authority to grant or deny requests for waiver or reduction of fees. The purpose of the proposal is to permit the Commission to recover the mounting costs of search and duplication services performed by Commission staff.

DATES: Written comments by August 31, 1981.

ADDRESS: Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, Reference Docket No. RM81-40.

FOR FURTHER INFORMATION CONTACT:

Paul W. Hartley, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426 (202) 357-8608

Ray A. Huber, Division of Public Information, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426 (202) 357-8380

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is proposing to amend § 3.8 and Part 375 of its regulations (18 C.F.R. Parts 3 and 375). Section 3.8 (together with § 1.36) generally describes procedures by which the public may request information and copies of public documents in the possession of the Commission. This proposal would amend § 3.8 by adding a new paragraph (k) to establish fees to be charged for search and duplication of all documents requested pursuant to the Freedom of Information Act (FOIA) (5 U.S.C. 552). The proposal would amend Part 375 to delegate, to the Director of the Commission's Division of Public Information, the authority to grant or deny requests for waiver, or reduction, of fees. The purpose of the proposal is to permit the Commission to recover the mounting costs of search and duplication services performed by Commission staff (staff).

I. Background

Section 552(a)(4) of the FOIA permits the Commission to promulgate regulations, after notice and comment, specifying a uniform fee schedule for search and duplication services performed by the Commission in response to requests from members of the public under the the FIOA. Fees must be limited to reasonably standard charges and may provide recoverly only of costs directly incurred by the Commission. Fees are to be waived or reduced, if the Commission determines that such waiver or reduction is in the public interest because the public generally would benefit from furnishing the information to the requester.

Currently, Commission regulations establish fees for only part of the search and duplication services which may be involved in responsing to FOIA requests under sections 552(a)(1), (2), and (3). The regulations provide for fees for

duplication performed by an independent contractor,[1] but do not establish fees for search and duplication services performed by Commisson staff. Whether the duplication is done by contractor or staff depends on whether the documents sought by the requester are public documents. If public, the documents are located in the Division of Public Information or in the Commission's central files. In these circumstances, search by staff is minimal and duplication can be performed by the contractor. However, if the documents are not considered public records and are not stored in the public files, a significant amount of staff time may be spent on search and duplication to respond to the information request. The Commission estimates that, in practice, staff services are a significant part of the processing of FOIA requests. Approximately 80 percent of the FOIA requests in the first quarter of 1981 required search and duplication services by staff.

Summary of the Proposed Rule

Paragraph (k)(1) of the proposed amendment to § 3.8 sets forth the definitions applicable to paragraph (k).

Paragraph (k)(2) of the proposed rule establishes the rates that will be charged for staff search time. These fees depend upon the level of staff engaged in the search and the amount of time spent. Search conducted by clerical staff would be charged a fee of $8.00 per hour. Eight dollars an hour represents, approximately, the mean salary of clerical staff (GS-9 and below). Search conducted by professional or managerial staff would be charged $16.00 per hour. This figure represents, approximately, the mean salary of professional and managerial staff (GS-10 and above). The search time would be charged in quarter hour increments.[2]

Paragraph (k)(3) of § 3.8 would establish the fees to be charged for duplication services. Duplication costs were determined by estimating the cost, per page, of using leased photocopy machines. The Commission recognizes that costs per page vary with volume of copies, as well as the price of paper and duplication supplies. However, after reviewing a breakdown of cost and volume estimates, the Commission determined that the average cost was approximately 10 cents per page.

Proposed paragraph (k)(4) of § 3.8 provides that no fees will be charged for staff search or duplication services performed in response to one, or a series of related, FOIA requests, if the assessed fees for those services totals $5.00 or less. Five dollars is the estimated cost to the Commission of billing fees. The purpose of this provision is to relieve the Commission of the billing cost if that cost is equal to or greater than the assessed fees.

Proposed paragraph (k)(5) provides that requesters may petition the Commission for a waiver or reduction in

[1] The Commission currently has a contract with TS Information Servcies, Inc. (TSI).

Contract: DE-AC39-79RC-10144.

Photocopies—$.20 per copy.

Reader-Printer copies—$.30 per copy.

Diazo Microfiche Duplicates—$1.50 per fiche.

Roll to Roll Film Duplicates (minimum of ½ hour increments). $15.00 per 100 ft. roll.

Minimum Order—$2.00.

Postage—Actual cost plus $.75 for orders that must be wrapped.

Creation of Microfiche masters (included paper index) $12.00 per fiches.

Surcharge for credit sales (Master Charge and VISA) 7% of cost.

Note.—Under the terms of the contract, any information which is on TSI's master microfiche file must be searched and duplicated by TSI. If the document is not in the fiche files, Division of Public Information determines whether the document is in Division of Public Information files, the Commission's central files, or another source. The contract provides that TSI will copy any documents properly marked and delivered by DPI.

[2] The methodologies for determining the fees for search and duplication services for FOIA requests differs from the methodologies that the Commission has been using in determining fees for other Commission services. While the FOIA permits the collection of only "direct costs" for government services, the Commission's other fees for government services are designed to collect both the direct and indirect cost to the government.

fees. Proposed § 375.312 would delegated, to the Director of the Division of Public Information, the authority to grant or deny these waivers or to reduce fees. The Director's determination, in accordance with paragraph (k)(5), would be whether the public generally would benefit if the Commission furnished the information to the requester without charge or at a reduced rate.

Proposed paragraph (k)(5) also provides that the waiver, or reduction, of fees must be requested at the time the FOIA request is filed with the Commission. The purpose of this requirement is to provide the Director of Public Information with sufficient time to evaluate a waiver or reduction petition, in view of the limited time permitted for response to an FOIA request. The FOIA [3] and § 1.36 of the Commission's regulations require the Commission to determine, within ten working days, [4] whether to comply with an FOIA request. Since a waiver or reduction petition is a significant part of an FOIA request, it should be evaluated concurrently with the FOIA request. If a requester requests a waiver or reduction of fees, the Commission will process the request for information at the same time it reviews the request for waiver or reduction. If the Commission denies the waiver or reduction of fees, the requester will be billed as determined by the Commission, unless the requester has indicated that an agreement should be reached regarding the waiver or reduction before the Commission begins processing the FOIA request, and that the 10 day FOIA limitation is waived until such agreement is reached.

II. Certification of No Significant Impact

The Regulatory Flexibility Act (RFA) [5] requires certain statements, descriptions and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities."

Pursuant to section 605(b) of the RFA, the Commission finds that sections 603 and 604 of the Act do not apply to the proposed rule, because, if promulgated, it will not have a significant economic impact on a substantial number of small entities. A breakdown of the requesters seeking information under the FOIA indicates that the number of small entities which will likely be affected by this rulemaking will not be significant. In the first quarter of 1981, the Commission received 29 FOIA requests. Of these, only six could be identified as a small business, small organization, small governmental jurisdiction, or small entity. While the Commission expects that the number of small businesses charged a fee will increase, it does not expect the increase will be such that the number of small entities will be considered "substantial."

More importantly, however, it is unlikely that this proposal would impose a significant economic impact on any small entities affected by this rule. The Commission estimates that the average number of documents received per FOIA request is 52 pages. Although the search costs will vary among requests and cannot be estimated, the duplication costs by staff for such a request would only be $5.20. Further, the Commission's regulations provide for a waiver upon petition to the Commission. During the past year, five requests for waiver were received, and five were granted. The Commission is continuing its waiver policies and anticipates that it will eliminate any unnecessary or disproportionate burden on requesters, especially small entities.

III. Notice and Comment Procedures

The Commission invites interested persons to submit written comments on the matter proposed in this notice. An original and 14 conformed copies of such

[3] 5 U.S.C. 552(a)(6).

[4] In unusual circumstances, a time extension of an additional 10 working days may be granted. 5 U.S.C. 552(a)(b)(B). 18 CFR 1.36(f)(3).

[5] 5 U.S.C. 601–612 (Pub. L. 96–354, September 19, 1980).

comments should be filed with the Commission by August 31, 1981. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. All comments should refer to Docket No. RM81-40.

Written comments will be placed in the Commission's public file and will be available for public inspection in the Commission's Division of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426. The Commission will consider all timely comments before acting on the matter proposed in this notice.

(Federal Power Act, as amended, (16 U.S.C. 782-828(c)), Natural Gas Act, as amended, (15 U.S.C. 717-717w); Department of Energy Organization Act, (42 U.S.C. 7101-7352); Freedom of Information Act, (5 U.S.C. 552))

In consideration of the foregoing, the Commission proposes to amend §§ 1.36 and 3.8 and Part 375 of Title18, Chapter I of the Code of Federal Regulations, as set forth below.

By direction of the Commission. Commissioner Holden dissenting.

Kenneth F. Plumb,

Secretary.

PART 1—RULES OF PRACTICE AND PROCEDURE

1. Section 1.36 is amended by adding between the heading and the text, the following parenthetical:

§ 1.36 Public information and requests.

(See also § 3.8(k) of this Chapter regarding Freedom of Information Act request fees.)

* * * * *

PART 375—THE COMMISSION

2. Part 375 is amended in the table of contents by adding, in the appropriate numerical order, a new section number and heading as follows:

Sec.

375.312 Delegation to the Director of the Division of Public Information.

3. Part 375 is amended in Supart C by adding a new § 375.312 to read as follows:

§ 375.312 Delegations to the Director of the Division of Public Information.

The Commission authorizes the Director of the Division of Public Information to waive or reduce fees in accordance with § 3.8 of this chapter.

PART 3—ORGANIZATION; OPERATION; INFORMATION AND REQUESTS

4. Section 3.8 is amended by adding between the heading and the text, the following parenthetical:

§ 3.8 Public information and submittals.

(See also § 1.36 of this chapter regarding public information and Freedom of Information Act requests.)

* * * * *

5. Section 3.8(b) is amended in the eighth sentence by replacing the word "Secretary" with the word "Commission".

6. Section 3.8 is further amended by adding a new paragraph (k) at the end thereof to read as follows:

* * * * *

(k) *Fees for Freedom of Information Act requests.*—(1) *Definitions.* For purposes of this paragraph the following definitions apply.

(i) "Freedom of Information Act request" means a written request for public records in the possession of the Commission, which request is filed pursuant to section 552(a)(3) of the Freedom of Information Act (5 U.S.C. 552) and in accordance with § 1.36 of this chapter.

(ii) "Professional employee" means an employee of the Commission whose official grade level is GS-10 or above.

(iii) "Clerical employee" means an employee of the Commission whose official grade level is GS-9 or below.

(2) *Search fees.* If Commission response to a Freedom of Information Act request requires search of Commission records, the requester will

be charged for the search at the following rates:

(i) $4.00 per quarter hour for search services performed by a professional employee; and

(ii) $2.00 per quarter hour for search services performed by a clerical employee.

(3) *Duplication fees.* If Commission response to a Freedom of Information Act request requires the duplication of documents, and:

(i) If the duplication is done by Commission staff, the requester will be charged 10 cents per photocopy plus postage; or

(ii) If the duplication is done by an independent contractor, the requester will be charged in accordance with a uniform fee schedule for photocopies, and microfiche and microfilm duplication, plus postage. The uniform fee schedule is set by contract with the independent contractor and may be obtained in person, by telephone, or by mail from the Division of Public Information.

(4) *No fees charged below minimum.* If the total fees assessed for search and duplication services performed by Commission staff in response to a Freedom of Information Act requests, or to a series of related request, are $5.00 or less, the Commission will not charge the requester for those services.

(5) *Waiver or reduction of fees.* At the time a Freedom of Information Act request is filed with the Commission, the requester may petition the Commission for waiver, or reduction, of the fees described in this paragraph. The requester should show that waiver or reduction of the fees is in the public interest, because the requester's receipt of the information primarily benefits the general public. If the Commission determines that waiver, or reduction, of fees is in the public interest, the requested information will be furnished without charge or at a reduced rate.

¶ 32,149 High-Cost Gas Produced From Tight Formations (Virginia-1)

46 F. R. 40043 (August 6, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Virginia-1)]

Virginia; High-Cost Gas Produced from Tight Formations; Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Commonwealth of Virginia, Department of Labor and Industry, Division of Mines and Quarries, that the Berea Sandstone be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on August 31, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on August 14, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

I. Background

On July 7, 1981, the Commonwealth of Virginia, Department of Labor and Industry, Division of Mines and Quarries (Virginia), submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Berea Sandstone located in the Plateau Region of southwestern Virginia, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulation, this Notice of Proposed Rulemaking is hereby issued to determine whether Virginia's recommendation that the Berea Sandstone be designated a tight formation should be adopted. Virginia's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Virginia recommends that the Berea Sandstone located in the Plateau Region of southwestern Virginia, an area of approximately 1, 603 square miles, encompassing all of Dickenson County and parts of Lee, Scott, Wise, Russell, Buchanan and Tazewell Counties, Virginia, be designated as a tight formation. The formation thickness ranges from 20 feet on the flanks of the plateau to over 125 feet in the central portion of the plateau. The Berea Sandstone lies between the underlying Devonian Shale sequence and the overlying Sunbury Shale (Coffee Shale on the driller's log).

III. Discussion of Recommendation

Virginia claims in its submission that evidence gathered and presented in support of this recommendation demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Virginia further asserts that all existing state and federal regulations will be followed to assure proper casing of fresh-water aquifer zones that are used for domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53458, August 12, 1980), notice is hereby given of the proposal submitted by Virginia that the Berea Sandstone, as described and delineated in Virginia's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before August 31, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Virginia-1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concering the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than August 14, 1981

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3432))

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Virginia's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (59) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation. * * *

(48) through (58) [Reserved]

(59) *The Berea Sandstone in Virginia. RM79–76 (Virginia-1).*—(i) *Delineation of formation.* The Berea Sandstone is found in the Plateau Region of southwestern Virginia, an area including all of Dickenson County, and parts of Lee, Scott, Wise, Russell, Buchanan, and Tazewell Counties, Virginia.

(ii) *Depth.* The formation thickness ranges from 20 feet to 125 feet, thickening toward the central portion of the Plateau Region. The depth to the top of the Berea ranges from 3,365 feet in northern Buchanan County to 6,028 feet in eastern Buchanan County.

* * * * *

¶ 32,150 High-Cost Gas Produced From Tight Formations (Texas-12)

46 F. R. 40044 (August 6, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas-12)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas subject to an incentive price (18 C.F.R. § 271.703). This rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Railroad Commission of Texas that the Frio Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on August 31, 1981. Public Hearing: No public hearing is scheduled in this docket as yet. Written request for a public hearing are due on August 14, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

Issued: July 30, 1981.

I. Background

On July 13, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Frio Formation located in the southeastern part of the state in Willacy County, Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Frio Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the LaSal Vieja (8 9680-9935) Field located in Railroad Commission District 4, in Willacy County, Texas be designated as a tight formation. The recommended area covers 7,400 acres, located approximately 2 miles west of the town of Raymondville, in the San Juan de Carricitos Grt., A-8 Survey. The formation is a Frio reservoir consisting of a number of sand stringers interbedded with shale sections. The sand stringers are believed to be in communication with each other. The reservoir is an anticlinal trap and is encountered in the Mitchell Energy Corporation's Harvey Geis No. 1 Well at a log depth of 9,730 feet with a log bottom of 9,864 feet. The formation thickness in this well is 134 feet.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public

hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53458, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Frio Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, on or before August 31, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas-12), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE, Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than August 14, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342.)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (80) to read as follows:

§ 271.703

Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(48) through (59) [RESERVED]

(60) *Frio Formation in Texas.* RM79–76 (Texas–12).

(i) *Delineation of Formation.* The Frio Formation is encountered in the LaSal Vieja (8 9680–9935) Field located in the central portion of Willacy County, Texas District No. 4.

(ii) *Depth.* The top of the Frio Formation is located at an approximate depth of 9,635 feet below sea level and extends to approximately a depth of 9,887 feet giving a maximum thickness of 252 feet.

* * * * *

¶ 32,151 Incremental Pricing

46 F. R. 41748 (August 17, 1981).

18 CFR Part 282

[Docket No. RM80–18]

Incremental Pricing

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission hereby gives notice of a proposed rulemaking in Docket No. RM80–18. On July 31, 1981, the Commission issued an Order Delineating Effect of Judical Action on Commission Regulations which recognized that the decision in *Process Gas Consumers Group v. United States Department of Agriculture* (46 FR 41034, Aug. 14, 1981) had a significant affect on this Commission's incremental pricing program. In the July 31 order the Commission noted its intent to treat this matter by a rulemaking.

The proposed rule will exempt from incremental pricing surcharges under Title II of the Natural Gas Policies Act of 1978, the boiler fuel use of natural gas to raise steam which is used as an integral part of the manufacturing process of fertilizer, agricultural chemicals, animal feed or food. This rule is being proposed pursuant to the Commission's authority under section 206(d) of the Act.

DATES: Comments must be received on or before August 31, 1981.

ADDRESSES: Comments may be mailed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. All comments should refer to Docket No. RM80–18.

Written comments will be placed in the Commission's public files and will be available for public inspection through the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Barbara Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357–8330

or

Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8511.

SUPPLEMENTARY INFORMATION:

In the matter of treatment under the Incremental Pricing Program of Natural Gas used in the manufacturing process for fertilizer, agricultural chemicals, animal feed or food.

Issued: August 14, 1981.

The Federal Energy Regulatory Commission (Commission) proposes to amend § 282.203 and to add a new § 282.210 to its rules to exempt from incremental pricing natural gas used as boiler fuel to raise steam employed in a processing function in the manufacture of fertilizer, agricultural chemicals, animal feed or food. Until recently, facilities utilizing natural gas in this manner had been claiming exemptions from incremental pricing as process users under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432) and various Commission regulations.

On June 30, 1981, the United States Court of Appeals for the District of Columbia issued an opinion in *Process Gas Consumers Group, et al.* v. *United States Department of Agriculture (PGCG)* (Nos. 80–1558 and 80–1603). That case held that natural gas used as a boiler fuel to produce steam, which steam is directly applied in the manufacturing process of products, is

not a process use. By that determination the Court effectively subjected such uses to incremental pricing.

This proposal would provide an exemption from surcharges from the incremental pricing program under section 206(d) of the NGPA.

I. Background

Title II of the NGPA requires the Commission, within certain guidelines, to institute and administer a federal incremental pricing program. The program is designed to pass through, by surcharge, to certain industrial facilities, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA.

Currently, the incremental pricing program applied to natural gas used as boiler fuel by large industrial facilities. Under Title II of the NGPA, the incremental pricing program was to be implemented in two phases. In Phase I, section 201 required the Commission to promulgate rules applicable to natural gas used as boiler fuel by large industrial facilities.[1] The Commission issued these rules on September 28, 1979, in Docket Nos. RM79-14 (Order No. 49, 44 FR 57726, October 5, 1979) and RM79-21 (Order No. 50, 44 FR 57754, October 5, 1979). These rules became effective on October 15, 1979.

Title II of the NGPA specifically exempts from the incremental pricing program for a temporary period [2] industrial facilities that use natural gas for an "agricultural use" as defined in section 206(b)(3) of the NGPA.[3] The final regulations implementing section 201 of the NGPA (Order No. 49) also implemented the agricultural use exemption from the incremental pricing program. Section 282.202(a) of the Commission's original regulations defined "agricultural use", *inter alia*, as any use of natural gas:

(1) which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA * * *.[4]

Immediately after issuance of the original regulations, the Commission received requests from and on behalf of Nitram, Inc. (which uses natural gas as boiler fuel in the production of ammonium nitrate fertilizer), to define the term "process fuel" that appears in the definition of "agricultural use" to include natural gas used as boiler fuel if the stream raised by the boiler forms an integral step in the manufacture of the end product. The Commission treated Nitram's request as a petition for reconsideration of Order No. 49, and except to the extent that the Commission gave notice of its intent to open a docket for the purpose of receiving further comments, denied the petition. *See* Order No. 49-A, issued December 27, 1979 (45 FR 767, January 3, 1980).

After Order No. 49-A was issued, the Secretary of Agriculture (Secretary) issued a proposal to define "process fuel" in the manner proposed by Nitram, Inc., for purposes of Title IV of the NGPA (44 FR 77187, December 31,

[1] Phase II rules, which would have subjected other industrial uses of natural gas to incremental pricing, were disapproved by the House of Representatives on May 20, 1980 (Resolution of Disapproval, H. Rep. 655).

[2] The "agricultural use" exemption is subject to an alternative fuel test as set forth in section 206(b)(2), but the Commission has postponed action on such test, with the approval of Congress. *See* Order No. 83, Docket No. RM80-29, issued May 1980 (45 FR 33601, May 20, 1980).

[3] Section 206(b)(3) of the NGPA defines "agricultural use" as follows:

(b)(3) AGRICULTURAL USE DEFINED.—For purposes of this subsection, the term "agricultural use," when used with respect to natural gas, means the use of natural gas to the extent such use is—

(A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or

(B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food

[4] Under Title IV (curtailment), the Secretary of Agriculture is authorized to certify "essential agricultural uses" which receive a priority during periods of gas curtailment.

1979).[5] The effect of the proposed definition, when applied to the Secretary's list of "essential agricultural uses" of natural gas, would have been to include as "essential agricultural uses" certain volumes of natural gas used as boiler fuel in the production of fertilizer, agricultural chemicals, animal feed or food.

After the Secretary proposed the definition several persons filed petitions for rehearing or clarification of Order No. 49–A to determine the impact that the proposed decision would have on the incremental pricing program if it were to be adopted. The petitions requested the Commission to clarify that, if the Secretary adopted the proposed definition of "process fuel" for purposes of certifying "essential agricultural uses," such "essential agricultural uses" would be exempt from incremental pricing as "agricultural uses" even though they were certified by the Secretary after the adoption of § 282.202(a) on October 15, 1979. The Commission denied those petitions for rehearing of Order No. 49–A, stating that it was not inclined to decide the question without the aid of further public comment. (45 FR 13068, February 28, 1980.) On the same day, February 21, 1981, the Commission issued a Notice of Opportunity to Comment on Whether a Rulemaking Proceeding Should be Established in Docket No. RM80–18 (Notice) (45 FR 13122, February 28, 1980). In the Notice, the Commission requested comments regarding exemptions from incremental pricing for natural gas used as boiler fuel to raise steam which in turn is used as an integral part of the manufacturing process of fertilizer, agricultural chemicals, animal feed or food.[6]

Thereafter, the Secretary issued a final rule adopting the proposed definition of "process fuel", as used in section 401 of the NGPA (45 FR 27741, April 24, 1980). As a result of this definition, boiler fuel users of natural gas who use steam directly in the manufacture of fertilizer, agricultural chemicals, animal feed or food became eligible for the second curtailment priority as "process" users. Many of these users also began claiming incremental pricing exemptions as "process" users pursuant to their interpretation of § 282.202(a) of the Commission's rules in conjunction with the Secretary's rule.

On October 6, 1980, the Commission issued in interim rule in Docket No. RM80–75 (45 FR 67276, October 9, 1980) amending § 282.202(a)(1) of its rules to provide that only "essential agricultural uses" certified by the Secretary before October 15, 1979 (the original effective date of § 282.202(a)) are automatically included in the definition of "agricultural use" for incremental pricing purposes. Uses of natural gas certified as "essential agricultural uses" by the Secretary after October 15, 1979, were not automatically included in the definition of "agricultural use" for incremental pricing purposes but were to be considered individually by the Commission, after opportunity for public comment.

The Commission issued a partial stay of that rule on October 23, 1980, the effect of which was to extend, on the basis of regulatory reliance, the claimed incremental pricing exemption for these "process" users who had filed affidavits prior to October 6, 1980 (45 FR 76681, November 20, 1981). Later, on April 23, 1981, the Commission issued a full stay of the interim rule in Docket No. RM80–75. The full stay permitted "process" users who had not filed affidavits prior to October 6, 1980, to file them and gain an exemption on the basis of § 282.202(a). (46 FR 25599, May 18, 1981.) This stay order was prospective only, the exemption taking effect as of the

[5] The Secretary proposed to define "process fuel" to mean "natural gas used to produce steam which in turn is directly applied in processing of products and for compression of products so that processing may take place, in addition to direct flame and precise heating applications of natural gas in processing of products. This does not include natural gas used for space heating, generation of hot water for plant cleaning and generation of electric power."

[6] 45 FR at 13123.

billing period for the month of May 1981 and extending until such time as the Commission acts otherwise. Accordingly, as of May 1, 1981, all "process" users who manufacture fertilizer, agricultural chemicals, animal feed and food, were able to file affidavits claiming incremental pricing exemptions on the basis of § 282.202(a), as stayed.

After the partial stay was issued, the Commission held public hearings in both Docket Nos. RM80–18 and RM80–75. Treatment under the incremental pricing program of natural gas used as boiler fuel to raise steam which forms an intergral step in the manufacturing process for fertilizer, and other processes, was discussed in the context of both dockets.[7]

On June 30, 1981, the United States Court of Appeals for the District of Columbia issued the opinion in *PGCG* that determines that natural gas used as boiler fuel to produce steam used in the manufacturing process of products is not a process use. On July 31, 1981, the Commission issued an Order Delineating Effect of Judicial Action on Commission's Regulations (46 FR 41034, August 14, 1981). The Commission stated that:

> By [the *PGCG*] opinion, the court determined that natural gas used as boiler fuel to produce steam, which steam in turn is directly applied in the manufacturing process of products, is not used as process fuel. This determination eliminates the exemption from incremental pricing that has previously been extended to such uses under Title II of the NGPA. (Mimeo at 1.)

The Commission went on to note, however, that "it opened [Docket No. RM80–18] to consider, *inter alia*, whether to institute a rulemaking to provide an incremental pricing exemption under section 206(d) of the NGPA for the above-described boiler fuel uses of gas." (Mimeo at 5.)

This Notice of Proposed Rulemaking is issued to provide further notice and opportunity to comment with regard to the issues raised initially in Docket No. RM79–14 (Order No. 49–A), and subsequently commented upon in Docket Nos. RM80–18 and RM80–75.

II. Discussion

The proposed rule would add a new § 282.210 to the Commission's rules to exempt from incremental pricing all natural gas used as a boiler fuel to raise steam which forms an integral step in the manufacturing process of fertilizer, agricultural chemicals, animal feed or food. A corresponding amendment would be made in § 282.203 by adding a new paragraph (d) to reference the new § 282.210.

Section 206(d) of the NGPA grants the Commission broad authority, subject to Congressional review, to exempt industrial facilities from incremental pricing.[8] As noted above, the issue of whether to grant such an exemption to boiler fuel users of natural gas in the manufacturing process for fertilizer, agricultural chemicals, animal feed or food has been raised and discussed in Docket Nos. RM79–14, RM80–18, and RM80–75. Over 50 comments were received in Docket No. RM80–18[9] as well as numerous comments addressing this issue in Docket No. RM80–75. The

[7] Commissioner George R. Hall stated that material provided in either docket would be considered in resolving the issues in both dockets and that materials in both Dockets RM80–18 and RM80–75 would be incorporated by reference. Docket No. RM80–18, Hearing of October 28, 1980, Transcript at 4.

[8] Section 206(d) of the NGPA provides:

Other exemptions.—

(1) IN GENERAL.—The Commission may, by rule or order, provide for the exemption, in whole or in part, of any other incrementally priced industrial facility or category thereof from the rule prescribed under section 201 (including any amendment under section 202 to such rule).

(2) CONGRESSIONAL REVIEW.—Any rule which provides for any exemption under this subsection may take effect after the expiration of the first 30 calendar days of continuous session of Congress (determined in accordance with section 507(b)) after a copy of such rule has been submitted to each House of the Congress, unless, during such 30 day period of continuous session of Congress, either House of the Congress adopts a resolution of disapproval described in section 507(c)(3), with respect to such rule.

[9] See Attachment A for list of commenters.

Commission has also held two public hearings at which 20 persons testified.[10]

As a result of the *PGCG* decision, the Commission has received several requests for immediate action on a rulemaking in Docket No. RM80–18.[11] Generally, the fertilizer, agricultural chemical and animal feed industries have filed petitions requesting the Commission to issue a section 206(d) exemption from incremental pricing as soon as possible. This group of petitioners will, as a result of the *PGCG* decision, become subject to incremental pricing on September 1, 1981.

The Commission has also received petitions in opposition to the granting of a section 206(d) exemption from incremental pricing for the use of gas in boilers to generate steam used in the manufacture of fertilizer, agricultural chemicals, animal feed and food. These petitions have come from local distribution companies and industrial trade groups.[12]

The Commission is issuing this Notice of Proposed Rulemaking to provide interested parties an additional opportunity to comment on this issue. The comment period is two weeks, a relatively brief period necessitated by the combination of the effect of the *PGCG* decision and scheduled Congressional adjournment. Late-filed comments will be considered only to the extent practicable.

As a result of the *PGCG* decision, the uses that are the subject of this docket will be incrementally priced as of September 1, 1981. If the Commission were to decide that those uses should be exempt under section 206(d) of NGPA, it should submit a final rule to Congress in September 1981 in order that the 30-day period for Congressional review may run before scheduled Congressional adjournment in October 1981. Otherwise, the subject uses would be incrementally priced until 1982.

The Commission believes that the previous opportunities to comment on this issue and the extensive records established in Docket Nos. RM80–18 and RM80–75 indicate that the public has been fairly informed of issues underlying this rulemaking. All comments will be fully deliberated by the Commission. Therefore, *comments submitted pursuant to the instant notice should not be duplicative of previously filed comments.*

The Commission particularly invites comments on the following issues:

1. What is the volume of natural gas used as boiler fuel to produce steam which is used in the production of (1) fertilizer, (2) agricultural chemicals, and (3) animal feed and food? How many individual facilities, by category, are represented in the volumes identified above?

2. What companies are the major producers of (1) fertilizer, (2) agricultural chemicals, and (3) animal feed and food? What fraction of their total sales result from these products?

3. To what extent will the average cost per unit of these products increase as the result of incremental pricing? What proportion of this increase, if any, will be absorbed by the producers of these products? What proportion will be passed on to consumers?

[10] Treatment under the Incremental Pricing Program of Natural Gas Used as a Boiler Fuel to Raise Steam Which Forms an Intergral Step in the Manufacturing Process for Fertilizer, Docket No. RM80–18, Hearing of October 28, 1980; Interim Rule Amending § 282.202(a) of the Commission's Regulations Under the Natural Gas Policy Act of 1978, Docket No. RM80–75, Hearing of October 28, 1980.

[11] Request for Immediate Action on Rulemaking, filed by The Fertilizer Institute, the National Council of Farmer Cooperatives, and the American Feed Manufacturers Association, filed July 8, 1981; Response of the Fertilizer Institute to Petition of the Process Gas Consumers Group and the Georgia Industrial Gas Group for Orders Dissolving Stay and Issuing Final Rule, filed July 29, 1981.

[12] Petition of the Process Gas Consumers Group and the Georgia Industrial Gas Group for Orders Dissolving Stay and Issuing Final Rule, filed July 15, 1981; Answer of the Process Gas Consumers Group and the Georgia Industrial Gas Group to Request for Immediate Action on Rulemaking, filed July 20, 1981; Motion of United Distribution Companies for Clarification, Dissolution of Stay and Termination of Rulemaking and Answer to Request for Immediate Action on Rulemaking, filed July 27, 1981.

4. Describe and, if possible, quantify the impact of increased energy cost in the fertilizer, agricultural chemical, and animal feed and food industries on American agricultural production.

5. Describe and, if possible, quantify the effect of an increase in the cost of these products on net farm income.

6. Is quantifiable data available to demonstrate a relationship between incremental pricing of the facilities in question and an impact on farmers?

7. Is quantifiable data available to demonstrate a relationship between incremental pricing of the facilities in question and an impact on consumers' food bills? On consumers' gas bills?

8. What percentage of each of these products, *i.e.* fertilizer, *etc.* is imported?

9. What is the impact of incremental pricing on American producers of fertilizer, *etc.*, with respect to their competitive position vis-a-vis: (1) foreign imports of these products; and, (2) domestic products manufactured with intrastate gas?

10. Is there a policy basis for exempting from incremental pricing the subject use of natural gas by the fertilizer, *etc.* industries and not exempting the same use of natural gas by other agricultural-related industries, *e.g.* manufacturers of tractors or crop dusters? By industries which have a signficant impact on other segments of the economy, such as the auto industry?

11. Is there a policy basis for exempting from incremental pricing the subject use of natural gas by the fertilizer, *etc.* industries and not exempting all other boiler fuel uses of natural gas by the fertilizer, *etc.* industries? By other agricultural-related industries, *e.g.* manufacturers of tractors or crop dusters? By industries which have a significant impact on other segments of the economy, such as the auto industry?

12. Should a section 206(d) exemption for facilities which manufacture fertilizer, *etc.*, be made specifically subject to an alternative fuel test such as the one set forth in section 206(b)(2) of the NGPA for "agricultural uses"?

13. What percentage of these facilities have installed alternative fuel capability for their boiler fuel? What fuels can be burned in these facilities with installed alternative fuel capability?

14. What standards could be applied to ascertain whether a particular use of steam is, as provided by new proposed § 282.210, an "integral part of the manufacturing process"? Should any uses be expressly excluded?

15. What are appropriate policy standards for Commission issuance of an exemption pursuant to section 206(d), and how do such standards apply to an exemption for manufacturers of fertilizer, agricultural chemicals, animal feed and food?

III. Congressional Review

The regulations below are being proposed pursuant to section 206(d) of the NGPA. Thus, if the regulations are adopted by the Commission as a final rule, they will be submitted to the Congress for review prior to taking effect. After the regulations are submitted to each House of Congress, they may take effect following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30 day period.

IV. Comment Procedures

The Commission invites interested persons to submit written comments on the matter proposed in this notice. An original and 14 conformed copies of such comments should be filed with the Commission on or before August 31, 1981. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. All comments should refer to Docket No. RM80-18.

Written comments will be placed in the Commission's public files and will be available for public inspection through the Commission's Office of Public Information, Room 1000, 825

North Capitol Street, N.E., Washington, D.C. 20426. The Commission will consider all timely comments before acting on the matters proposed in this notice.

In view of the public hearings that have previously been held on this matter, the Commission is not scheduling further public hearings.

(Natural Gas Policy Act of 1978) 15 U.S.C. 3301; Department of Energy Organization Act, 42 U.S.C. 7701; Administrative Procedure Act, 44 U.S.C. 1501; E.O. 12009, 42 CFR 46267 (1970))

In consideration of the foregoing, the Commission proposes to amend Part 282, Subchapter I of Chapter I, Title 18 of the *Code of Federal Regulations,* as provided below.

By the direction of the Commission. Commissioner Holden voted present.

Kenneth F. Plumb,

Secretary.

1. The Table of Contents for Subpart A of Part 282 is amended to add a new § 282.210 entitled "Exemptions for natural gas used in the manufacturing process of fertilizer, agricultural chemicals, animal feed and food."

2. Section 282.203 is amended by adding a paragraph (d) to read as follows:

§ 282.203 Exempt end-uses.

* * * * *

(d) *Exemptions for natural gas used in the manufacturing process of fertilizer, agricultural chemicals, animal feed and food under section 206(d).* Natural gas used as a boiler fuel in the manufacture of fertilizer, agricultural chemicals, animal feed or food is exempt from incremental pricing according to the provisions set forth in § 282.210.

3. Part 282 is amended by adding a new § 282.210 to read as follows:

§ 282.210 Exemptions for natural gas used in the manufacturing process of fertilizer, agricultural chemicals, animal feed and food.

Natural gas used as a boiler fuel to raise steam which in turn is used as an integral part of the manufacturing process of fertilizer, agricultural chemicals, animal feed or food is exempt from incremental pricing under Title II of the Natural Gas Policy Act of 1978 and Part 282 of the Commission's rules.

Attachment A

Commenters in Docket No. RM80-18:
Gulf Oil Corporation
Vertac Chemical Corporation
FS Services, Inc.
Kaiser Aluminum & Chemical Corporation
Public Service Electric and Gas Company
American Feed Manufacturers Association, Inc.
American Gas Association
Farmland Industries, Inc.
Pacific Gas and Electric Company
Nitram, Inc.
Vistron Corporation
Allied Chemical Corporation
The Public Utilities Commission of the State of California
CF Industries, Inc.
New England Gas Distributors
United Distribution Companies
The Fertilizer Institute
N-Ren Corporation, St. Paul Ammonia Products Division
The Process Gas Consumers Group, The American Iron and Steel Institute, and the Georgia Industrial Gas Group
The United States Brewers Association, Inc.
Terra Chemicals International, Inc.
Columbia Nitrogen Corporation and Nipro, Inc.
Kal Kan Foods, Incorporated
The Brooklyn Union Gas Company
Beker Industries, Corporation
The National Council of Farmer Cooperatives
Armour Pharmaceutical Company
Valley Nitrogen Producers, Inc.
Eli Lilly and Company
Agrico Chemical Company
Miles Laboratories, Inc.
J. R. Simplot Company
Stauffer Chemical Company
Schenley Distillers, Inc.
Consolidated Edison Company of New York, Inc.
American Dry Mile Institute, Inc.
Whey Products Institute
Northwest Pipeline Corporation
Department of Agriculture
United States Senate—Richard Stone and Lawton Chiles

¶ 32,152 Fees Applicable to Natural Gas Pipelines

46 F. R. 42075 (August 19, 1981).

18 CFR Part 159

[Docket No. RM79-63]

Fees Applicable to Natural Gas Pipelines

Issued: August 12, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission gives notice that it proposes to amend prospectively its regulations regarding the collection of fees under the Natural Gas Act. Under the proposed new fee schedule, a fee would be assessed for the processing of applications for a wide variety of authorizations, including certificates of public convenience and necessity, abandonments, and import and export authorizations. The proposed rule would establish a separate procedure for the direct billing of processing costs to the sponsors of the Alaska Natural Gas Transportation System. The proposed fee schedule would apply prospectively to applications filed after October 1, 1981.

DATE: Written comments by September 4, 1981.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Reference Docket No. RM79-63.

FOR FURTHER INFORMATION CONTACT: Kenneth F. Plumb, Secretary, Room 9310, 825 North Capitol St., NE., Washington, D.C. 20426, (202) 375-8400.

SUPPLEMENTARY INFORMATION:

I. Background

By this notice, the Federal Energy Regulatory Commission (Commission) proposes to amend Part 159 of its regulations which impose fees upon certain natural gas companies for the processing of applications filed under the Natural Gas Act (15 U.S.C. sections 717-717w.) This proposal would amend Part 159 to impose fees for a variety of applications filed by interstate pipelines, including, but not limited to, applications for authorizations under the Natural Gas Act. In addition, a separate procedure for the direct billing of processing costs is established for the Alaska Natural Gas Transportation System (ANGTS). The purpose of the proposed amendments is to make the imposition of fee more equitable by spreading the burden of administrative costs attributable to the Commission's pipeline certificate activities among a wider variety of applicants and by basing the fee upon the degree of Commission attention required for processing the application, rather than on the size of the project as is currently done. The amendments are not expected to increase the total amount of fees collected each year under Part 159.

At present, Part 159 imposes fees upon interstate pipelines for a limited number of applications under the Natural Gas Act and related authorities. In § 159.1, a fifty dollar filing fee is assessed upon a number of applications that relate to jurisdictional pipeline activities. Section 159.2 specifies a flat rate fee based upon the projected construction cost for certificates authorizing the construction or acquisition of facilities. Projects which cost less than $7,000 are exempt from the fee.[1] In Order No. 317, promulgated in Part 159, the Commission took the position that a fee proportional to the size of a project is a fair and equitable method for apportioning processing costs. Accordingly, the present fee structure assesses a fee equal to sixty-five one-thousandths of

[1] 35 F.P.C. 30 (1966), *clarified on rehearing*, 35 F.P.C. 392 (1966).

1% (0.0065) of the estimated cost of construction of new or acquired facilities, which fee is to be paid within 30 days following issuance of a certificate application notice. An issuance fee equal to one hundred and thirty one-thousandths of 1% (0.00130) of the estimated cost of construction is due within 30 days following the grant of a certificate. Applications for other authorization under the Natural Gas Act, section 5 of the Outer Continental Shelf Act, 43 U.S.C. § 1334, or Executive Order 10485 13 C.F.R. 970 (1949–1953 compilation), which do not involve construction, must be accompanied by a $50 filing fee.

On August 2, 1979, the Commission issued a notice of inquiry [2] in this docket to permit the Commission to reexamine the fees applicable to certificates of public convenience and necessity which authorized the construction of facilities pursuant to section 7(c) of the Natural Gas Act. After considering the comments filed in response to the notice of inquiry the staff has conducted a study of the Commission's certificate process. The new fee structure proposed here reflects the consideration of the issues raised in those comments and staff study

The Commission believes that the proposed rule would apportion the costs of the Commission's pipeline certificate operations more equitably between construction certificate proceedings and other applications not involving construction which also require substantial Commission attention. Under the proposed rule, fees would be assessed against applicants based upon the degree of Commission attention required for processing. In addition, a separate procedure is created to bill processing costs annually to the sponsors of the ANGTS in recognition of the unprecedented size and complexity of the ANGTS.

II. Summary of Proposal

The proposed rule would establish four categories of fees. The first involves applications that either do not require the Commission to incur substantial costs or, if substantial costs are incurred, do not confer substantially greater benefits on the applicant than on other members of the public. These applications would continue to be assessed a nominal $50 fee upon the filing of the application. This $50 fee is designed to recover docketing costs. The second includes routine applications which the Director of the Office of Pipeline and Producer Regulation can decide without Commission consideration. These applications would be assessed a $1,000 fee. The third includes more complex certificate cases which may be considered by the full Commission without an evidentiary hearing. These applications would be assessed a total fee of $4,000. The fourth category includes certificate applications which are set for evidentiary hearing. They would be assessed fee payable in four installments which total $18,500, if the proceeding goes to hearing.

III. Basis for Proposed Fee Schedule

A. *Legal standard.*

Title V of the Independent Offices Appropriation Act of 1952, (Title V) (69 Stat. 290, 31 U.S.C. section 483a) provides:

> [A]ny work, service, publication, report, document, benefit, privilege, authority, use, franchise, license permit, certificate, registration, or similar thing of value or utility performed, furnished, provided, granted, prepared, or issued by any Federal agency to or for any person shall be self-sustaining to the full extent possible. and the head of each Federal agency is authorized by regulation to prescribe therefor such fee, charge. or price. if any as he shall determine. in case none exists. or redetermine. in case of an existing one. to be fair and equitable taking into consideration direct and indirect cost to the Government. value to the recipient. public policy or interest served, and other pertinent facts and any amount so determined or redetermined shall be collected and paid into the Treasury as miscellaneous receipts.

[2] 44 FR 47348 (1979).

The most reliable guidelines issued by an agency on this section, Budget Circular A–25 [3], state that agencies should charge a fee for each measurable unit or amount of government service or property provided to an identifiable recipient if the recipient derives more substantial benefits than those that accrue to the general public.[4] Further interpretation by the Court of Appeals for the D.C. Circuit [5] indicates that agencies must justify the assessment of a fee (by identifying the particular service or benefit it reimburses) and calculate the fee on a cost basis. In light of the Commission's and the court's interpretation of Title V, the Commission has attempted in this proposal to:

1. identify, in units as small and discrete as practical, the services to be reimbursed;

2. exclude expenses incurred to serve an independent public interest; and

3. identify and allocate the recoverable expenses on the basis of cost incurred for each unit of service.

B. *Identification of reimbursable units of services.*

As the Court of Appeals for the D.C. Circuit noted in *Electronic Industries Ass'n.*, in designing a fee schedule, the Commission must identify units of its regulatory activities that provide a service:

> [W]e interpret the statute and the Supreme Court decisions to require an allocation of costs to the smallest unit that is practical. In most cases, we expect this unit will be the classes of carriers or applicants or guarantees or services which the [FCC] has already singled out for separate treatment in its 1975 fee schedule.

554 F.2d at 1116. Applying this principle to the pipeline certificate area, the Commission concludes that individual applications are in most cases, the smallest practical unit [6] of activity for assessing a fee. The pipeline certificate area processes ten categories of applications:

1. Municipalities or distributors requesting service under section 7(a) of the Natural Gas Act.

2. Pipelines seeking certificates for construction or acquisition of facilities under sections 7(c) and (e). (This category varies greatly in terms of complexity and amount of processing required.)

3. Pipelines seeking section 7(c) certificates which do not involve construction of facilities (*e.g.* sales for resale, transportation).

4. Pipelines applying for authorization under sections 311 and 312 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. sections 3371 and 3372), which require prior Commission approval.

[3] Bureau of the Budget Circular A–25 (September 23, 1959). This interpretation has been quoted by the Supreme Court as "the proper construction of the Act" in *New England Power v. FPC*, 415 U.S. 345, 351 (1974).

[4] Budget Circular A–25 at 1–2:

> *General Policy.* A reasonable charge . . . should be made to each identifiable recipient for a measurable unit or amount of Government service or property from which he derives a special benefit.
>
> For example, a special benefit will be considered to accrue and a charge should be imposed when a Government-rendered service:
>
> (a) Enables the beneficiary to obtain more immediate or substantial gains or values (which may or may not be measurable in monetary terms) than those which accrue to the general public (e.g., receiving a patent, crop insurance, or a license to carry on a specific business); or
>
> (b) Provides business stability or assures public confidence in the business activity of the beneficiary (*e.g.*, certificates of necessity and convenience for airline routes, or safety inspections of craft).

[5] *Electric Industries Ass'n* v. *FCC*, 554 F.2d 1009, 1117 (1976) states:

> First, the Commission must *justify* the assessment of a fee by a clear statement of the particular service or benefit which it is expected to reimburse. Second, it must calculate the *cost basis* for each fee assessed. This involves (a) an allocation of the specific direct and indirect expenses which form the cost basis for the fee to the smallest practical unit; (b) exclusion of any expenses incurred to serve an independent public interest; and (c) a public explanation of the specific expenses included in the cost basis for a particular fee, and an explanation of the criteria used to include or exclude particular terms.

[6] In cases involving evidentiary hearings or Commission consideration on rehearing of an order . . . multiple payments will be collected.

5. Pipelines seeking abandonment authorizations under section 7(b) of the Natural Gas Act.

6. Pipelines filing curtailment plans under section 4 of the Natural Gas Act and Title IV of the NGPA.

7. Pipelines seeking declarations of exemption under section 1(c) of the Natural Gas Act.

8. Pipelines applying for authorization to import or export natural gas under section 3 of the Natural Gas Act and Executive Order 10485.

9. Pipelines seeking other declaratory orders and determinations pertaining to non-rate issues.

10. Parties to proceedings applying for rehearing of Commission orders issued in any of the above categories (Any party to a certificate proceeding, including the applicant, may seek rehearing.)

The present fee structure recovers significant processing costs only from applicants seeking certificates for construction or acquisition of facilities (the second category). The Commission proposes to expand the new fee schedule to recover processing costs from all categories of applications, except those that do not involve significant processing costs and those in which the value to the applicant is arguably much less than the costs to the government (categories 6 through 10).

The Commission clearly performs a service when it accepts and considers applications for approval or authorization of some activity Consideration of these applications affords the applicant significant and substantial benefits. For example, a certificate of public convenience and necessity under the Natural Gas Act permits an applicant to engage in the transportation and sale of natural gas for resale in interstate commerce. A pipeline holding such a certificate may exercise the emminent domain authority of section 7(h) of the Natural Gas Act. Such certificate regulation also protects the substantial investment required for pipeline construction, and determines, in part whether the construction investment will be eligible for recovery from the pipeline's ratepayers, under the terms of the certificate. The analysis and drafting performed by the Commission when processing a certificate application is the direct result of the applicant's decision to engage in the proposed transaction. But for the application, the Commission's efforts would not be performed. In each instance where an application fee is assessed under the proposed schedule, the applicant will derive a substantial benefit, and the Commission will incur expense in processing the application. The goal of the proposed rule is to enable the government to recover a portion of the costs incurred in processing applications for pipeline certificates and related authorizations.

Exclusion of certain activities. In certain applications, the applicant does not receive a significantly greater benefit than that received by other members of the public. In such cases, no fee is charged for processing cost under the proposed fee schedule. Thus, no fee is charged for processing curtailment plan tariffs, which allocate gas among the customers of a pipeline during times of shortage and serve to protect large categories of end-users. Similarily, declaratory orders, which relieve uncertainty or make jurisdictional determinations, in some instances benefit the public as a whole as well as the specific applicant. Even though the applicant has requested the Commission's services, the value to the applicant is arguably much less than the direct and indirect costs to the government. Therefore, only a $50 nominal fee is proposed to defray docketing costs.

A second area of costs which have been excluded from recovery is time and expenses devoted to policy coordination, case management and administration. The Commission's existing management information system allocates professional staff time between "docketed" and "non-docketed" activities. Non-docketed tasks include administrative responsibilities, answering inquiries from Congress and the general public,

policy formulation, and personnel matters. Although certain efforts that benefit identifiable parties have been classified as a "non-docketed" cost, the Commission has elected to exclude all non-docketed staff activities from its determination of application processing times. As a result, the proposed fee structure does not recover any non-docketed certificate activities, even though these expenses represent indirect costs which may be lawfully recovered under Title V.

A third area of costs which have been excluded involve the expenses devoted to enforcement, curtailment, and rulemaking proceeding in the pipeline certificate area. None of these costs have been included in the proposed fee schedule and such proceedings have been excluded from the calculation of average processing times.

A fourth area receiving special treatment is the cost of applications set for formal evidentiary hearing. The cost of formal evidentiary hearings can be attributed to administrative law judges (ALJ), trial staff counsel and technical witnesses, and advisory staff which later evaluates the record. The treatment of hearing costs have varied under the fee schedules of other federal agencies, and the reviewing courts have taken the position that the recovery of some hearing costs are permissible under Title V.

The Nuclear Regulatory Commission (NRC) fee structure recovered the cost of "uncontested hearings" where the trial staff did not oppose the issuance of a license, but the costs of hearings where staff opposed a license were not recovered. (See 42 FR 22149, 22156 May 2, 1977). On appeal, Mississippi Power & Light claimed that this distinction was arbitrary, but the Fifth Circuit affirmed the NRC noting:

> Because [uncontested hearing] costs are necessarily incurred by the agency in providing a service to the applicant, they should be assessed against the applicant.

Mississippi Power & Light v. *NRC*, 601 F2d 223, 231 (1979).

The 1975 FCC fee structure, held to be invalid by *Electronic Industries Assn.*, averaged in the costs of cases which went to hearing with those which did not go to hearing. Although the 1975 fee structure was specifically challenged for failing to distinguish between the hearing and non-hearing cases, the D.C. Circuit did not view the distinction as a mandated part of an acceptable cost allocation. The Supreme Court in *National Cable Television Ass'n.* v. *United States*, 415 U.S. 336, 343 (1974), quoted with approval from the legislative history of Title V, which noted that in exchange for a radio license a license holder "should pay some of the cost of the hearings."

Accordingly, the proposed fee schedule will reflect the additional costs of applications set for formal hearing by imposing those cases a higher fee than for those not set for formal hearing. However, the Commission does not propose to collect the average full cost of an evidentiary hearing under the proposed fee structure. The calculations described below indicate that the Commission incurs an averge direct cost of $73,206.26 in certificate cases which are set for Formal evidentiary hearing. Rather than attempt to collect this amount in each case, the Commission has elected in its discretion to recover only the average additional advisory staff and ALJ costs which are associated with cases set for hearing, $18,500. In addition the Commission proposes to collect the fee in four payments, which will result in a lower fee in cases concluded by settlement or for which an initial decision was omitted.

C. *Allocating recoverable expenses on the basis of costs.*

The Commission's staff has analyzed the costs of processing applications which arise in the pipeline certificate area of the Commission's jurisdiction. The following analysis identifies the budgeted costs for processing applications in this area and derives an average cost of $16.57 per hour of staff effort. This cost factor is then applied

against the average time to process three identifiable categories of applications to calculate the proposed fee structure. Finally, the projected revenue from the proposed fee structure is compared with the costs of the Commission's certificate operation to demonstrate that the proposed rule would recover only 36 percent of the Commission's operating costs in the certificate area.

Cost per workhour. A determination of the applicable direct and indirect costs for processing applications depends, in part, on an average hourly personnel cost. Rather than using a Commission-wide average personnel cost, the proposed fee schedule is based upon an hourly rate which reflects only those Commission offices which process certificate applications.

The Commission has divided its operations into several program areas for budgetary purposes. For the pipeline certificate area, the Commission has budgeted a total of $10,097,000 for personnel compensation and benefits costs ($9,834,000), and for travel and transportation costs ($263,000). This total does not reflect the $2,652,000 cost of office space rents, communication (such as telephones and postage), utilities, printing, services of outside contractors, supplies and equipment (such as word processors) in the pipeline certificate area. Although such costs could be properly recovered under Title V, for administrative ease, they have not been included in the calculation of expenses to be recovered under the proposed fee schedule. The $10,097,000 certificate area cost does not include the Alaska Gas Project Office which has been established to process the ANGTS applications.[7]

Two-hundred and ninety-three staff members are assigned to the pipeline certificate area. Assuming 2080 work hours in each year, the average cost of one hour of work is $16.57 for the pipeline certificate area.

Design of fee categories. The Commission's pipeline certificate processing costs must be allocated among the identifiable beneficiaries of these services. As noted above, the smallest practical unit of regulatory activity is the individual application. However, pipeline applications vary in complexity from the routine to the extreme complexity of the ANGTS. Such a spectrum of complexity is reflected in the sliding scale fees currently prescribed in § 159.2. The proposed rule would divide the Commission's certificate cases into three broad categories for the purposes of the proposed fee schedule. Delegated cases involve the least analysis and are signed by the Director of Pipeline and Producer Regulation without review by individual Commissioner offices.[8] Non-formal cases, which require Commission action, involve more effort because they are reviewed by the Commission and present more complex factual and legal issues. Formal hearing cases which undergo an evidentiary hearing under the Administrative Procedure Act (5 U.S.C. section 554), require considerably more staff time than the other two categories because of the depth of factual and legal investigation required to consider such a case.

The 293 staff members assigned to the pipeline certificate area divide their efforts between docketed and non-docketed tasks. According to the Commission's management systems, 106

[7] The Alaska Gas Project is a separate budget area in the 1981 fiscal year budget, but is combined with the certificate area budget for subsequent years.

[8] The staff analysis of processing times was based upon those items delegated to the Director of the Office of Pipeline and Producer Regulation prior to the adoption of Order No. 147 on May 22, 1981 (46 FR 29700 (1981).) Order No. 147 expanded the Director's authority to pass upon additional, and more time-consuming, applications. Since many of the items delegated to the Director under Order No. 147 are the subject of the blanket certificate proposal pending in Docket Nos. RM81-19 and RM81-29, the average processing time for delegated cases was not revised to reflect the items transferred in Order No. 147.

work-years are devoted to non-docketed matters during fiscal year 1981. Approximately 187 work-years (2244 work-months) are devoted to processing docketed cases. This work is performed by the Commision's offices as follows:

Office	Work-months
Office of Pipeline and Prod. Regulation	1,621.5
Office of the General Counsel	283.6
Administrative Law Judges	85.5
Office of the Chief Accountant	6.0
Office of Opinions and Review	78.3
Office of Regulatory Analysis	68.2
Office of the Secretary	15.9
Commissioner's Offices	181.7

The following table summarizes the staff effort required for each category of applications. Only those hours allocated to docketed cases have been included.

Type case	Average time [1] hours
Delegation	80
Non-Formal	250
Formal hearing	4,418

[1] Average professional times to process cases in the pipeline certificate area are derived from studies of selected case processing times, excluding the ANGTS, enforcement curtailment and rulemaking proceedings.

The average processing cost for the three categories of applications can be calculated by multiplying the average processing time by the hourly staff cost.

Average cost to process 1 delegation case 80 hrs × $16.57 = $1,325.60

Average cost to process 1 non-formal case 250 × 16.57 = 4,142.50

Average cost to process 1 formal case 4,418 × 16.57 = 73,206.26

The Commission has devoted considerable attention to the recovery of costs entailed in conducting evidentiary hearings. The Commission's budget allocated 40,136 hours of advisory staff and ALJ resources to formal certificate cases. This represents an average 892 work hours per case. At $16.57 per hour, an additional fee of $14,500 should be charged to recover these costs over and above the fee for informal cases. The following table shows a proposed schedule for collecting this additional time:

	Delegated	Statutory hearing	Formal hearing
Filing	$1,000	$1,000	$1,000
Hearing order issued			3,000
Issuance of initial decision			5,000
Issuance of Commission order		3,000	9,500
Total	1,000	4,000	18,500

The proposed fee structure would provide for fee payments at five stages in the processing of an application. At the time that a certificate application is filed, it could potentially qualify for any one of the three fees. Hence, a common $1,000 filing fee must accompany the application in all three fee categories. A second $3,000 fee payment is collected upon the issuance of the order indicating whether an evidentiary hearing will be held in the proceeding. In order to reflect the greater costs involved in Commission consideration of briefs on exception to initial decisions, the remaining fee for evidentiary hearing cases has been divided into two additional payments. A $5,000 payment is due 30 days after the issuance of an initial decision. If initial decision in the case is settled prior to an initial decision, or if the waived or omitted, then the $5,000 payment will not be collected. An additional $9,500 payment is collected 30 days after the issuance of a Commission opinion or order after an initial decision. Again, if a settlement is reached before this stage, or if no party filed exceptions to the initial decision, the $9,500 will not be collected.

Comparison of costs and projected fees revenues. As shown below, if the proposed fee schedule had been in effect during fiscal year 1981, at most $3,215,000 would have been collected.

The proposed fee schedule would be expected to recover $3,179,150 in fiscal year 1982. These projections are based upon the staff's estimate of the number of new applications to be received during the two years. The estimate for possible total fees to be collected is calculated below by multiplying the

proposed fee for each category times the dollar fee proposed. This calculation represents a maximum fee because it assumes that each formal certificate case will reach the Commission without a settlement.

Case categories	Fee		Fiscal year 1981 Cases	Fiscal year 1981 Revenues	Fiscal year 1982 Cases	Fiscal year 1982 Revenues
Delegation	$1,000	×	126	$126,000	124	$124,000
Non-formal	4,000	×	563	2,252,000	555	2,220,000
Formal	18,500	×	45	832,500	45	832,500
Rehearings	50	×	90	4,500	[1]53	2,650,000
Projected total fee revenue				3,215,000		3,179,150

[1] Based upon actual count for fiscal year 1979.

These projected fee revenues should be compared against the personnel and travel costs of the pipeline certificate area. As noted above, the $10,097,000 budgeted for this area includes enforcement, rulemaking and curtailment personnel. If the $1,275,048 cost of the 37 work-years assigned to these functions are excluded, the projected fee revenue should be compared against the remaining $8,821,952. Therefore, the proposal could possibly recover 38% ($3,215,000/$8,821,952) of the personnel and travel costs budgeted for pipeline certificates in fiscal year 1981.

IV. Alaska Natural Gas Transportation System

On October 22, 1976, the Alaska Natural Gas Transportation Act (ANGTA) (15 USC § 719) was enacted to provide expedited processing of the authorization necessary for the construction of an ANGTS extending from the Prudhoe Bay Unit of Alaska to the lower 48 states. Prior to the enactment of ANGTA, the Commission conducted a protracted evidentiary proceeding between competing applicants seeking to construct the ANGTS. The Congress, through the enactment of ANGTA, shifted the final responsibility for selecting an ANGTS sponsor from the Commission to the President. In addition, the President, through Reorganization Plan No. 1 of 1979, 44 FR 33663, 93 Stat. 1373, shifted certain responsibilities for monitoring compliance with section 7 of the Natural Gas Act from the Commission to the Office of the Federal Inspector for the ANGTS. These changes create a unique role for the Commission in the certification of the ANGTS.

Size also makes the ANGTS unique among pipeline certificate cases. The ANGTS is the largest privately financed construction project ever undertaken. In addition, the project's magnitude and geographical diversity have raised unprecedented technical issues, whose mastery required a substantial investment of staff resources. The Congressional mandate for expedition has imposed further demands upon the level of staff resources which must be devoted to the processing of ANGTS certificate applications. Accordingly, the Commission has excluded the processing of certificates which are necessary or related to the construction and initial operation of the ANGTS from the scope of its certificate fee review and from the proposed fee schedule. Instead the proposed rule provides for the annual direct billing of the ANGTS processing cost to the project's sponsors.

V. Comments in Response to the Notice of Inquiry

The Notice of Inquiry issued August 2, 1979, requested suggestions regarding fees applicable to certification of the construction of pipeline facilities. Eight

timely and two untimely comments were filed. Two challenged the basic framework of the fee structure on the grounds that an applicant should not be charged a fee for activities which serve an independent public interest. Other commenters urged that fees be determined on a case-by-case basis, while others simply suggested modification of the existing construction cost based fee structure. Additional issues raised in the comments involved proceedings for billing, and the effect any new rule issued by the Commission would have on pending applications.

A. *Fees for services which benefit the public interest.*

Two of the commenters insisted that no fee structure imposed by the Commission is valid unless it carefully distingishes between the cost incurred to benefit the public interest, and those incurred to benefit the particular applicant. They argued that fees should not reimburse the Commission for any cost incurred to discharge its public responsibilities, and would require that application processing costs be apportioned between the public and private interests. In the Commission's view, these two commenters misconstrue both the statute and subsequent cases. The cost apportionment argument raised in these comments is identical to the challenge advanced by Mississippi Power and Light against the NRC fee schedule. The Fifth Circuit rejected that same argument in *Mississippi Power and Light* v. *NRC*, 601 F.2d 223, 229–30 (5th Cir. 1979), *cert. denied*, 444 U.S. 1102 (1980):

> [The NRC] takes the position that it is not required to segregate public and private benefits and that it may recover the full cost of providing a service to a private beneficiary, regardless of whether that service may also benefit the public. We agree with the Commission.
>
> Our position is consistent with the view of the IOAA taken by the Supreme Court in *New England Power*. There, the Court cited with approval a 1959 Bureau of the Budget Circular which the Court felt represented a proper construction of the IOAA. In interpreting the Act, the Bureau opined: "Where a service (or privilege) provides special benefits to an identifiable recipient above and beyond those which accrue to the public at large, a charge should be imposed to recover *the full cost* to the Federal Government of rendering that service." . . .
>
> It is true, as the petitioners point out, that the Court in *National Cable* criticized the FCC for assessing fees based upon a formula contrived to reimburse the Commission for its total cost of supervision. But here, the NRC does not attempt to recoup all of its regulatory costs; it seeks only to recover the total cost of providing services to private beneficiaries.
>
> The District of Columbia Circuit has also rejected the suggestion of an allocation requirement. In *Electronic Industries Association* v. *FCC*, 180 U.S. App. D.C. 250, 554 F.2d 1109 (1976), the Court found that the FCC was not prohibited from charging an applicant for the full cost of rendering services to him, even though some incidental public benefit might flow from the service provided.
>
> In addition to being supported by persuasive if not controlling precedent, this approach comports with the clear legislative intent that agency services be "self-sustaining to the full extent possible." 31 U.S.C.A. § 483a. To impose the petitioners' allocation requirement would saddle agencies with the impossible task of sorting out public from private benefits, with the likely result that most agency fees would be reduced to mere tokens. In conclusion, we hold that the NRC may recover the full cost of providing a servce to an identifiable beneficiary, regardless of the incidental public benefits flowing from the provision of that service." [footnotes omitted].

B. *Suggested fee schedules.*

Two commenters proposed that fees be determined on a case-by-case basis for projects with a high level of complexity or size. In the alternative, one recommended a $195,000 limit on the filing fee due in any particular certificate proceeding.

In our view, assessing a unique fee in each of the thousands of certificate proceedings conducted by the Commission is administratively unworkable. Agencies have repeatedly grouped applications into fee categories and assessed a uniform fee applicable to

the entire category. The proposed rule takes this approach.

Neither Budget Circular A–25 nor the courts anticipate a separately computed fee for each certificate application. "Costs shall be determined and established from the best available records in the agency, and new cost accounting systems will not be established solely for this purpose." Budget Circular A–25 at 3.

The courts have repeatedly recognized that approximations and averaging between similar beneficiaries is permissible. "To be valid, a fee need only bear a *reasonable* relationship to the cost of the services rendered by the agency." *National Cable II,* 554 F.2d at 1108. The accounting system and the very structure of the fee itself may take averaging and approximations into acount. "This is not to say that the Commission must calculate the exact cost of servicing each individual; that would be an impossible task. Any computation such as those must necessarily be based on numerous approximations and can only be expected to be accurate within reasonable limits." *National Cable II,* 554 F.2d at 1105; *accord, National Association of Broadcasters* v. *FCC,* 554 F.2d 1118, 1130 (D.C. Cir. 1976). "It should be stated that we are not requiring exact calculations, just reasonable approximations. The ability to recoup both 'direct and *indirect costs* to the Government' does allow for some range and latitude in effecting a reasonable attribution of costs." 554 F.2d at 1130.

Finally, two commenters recommend that the Commission retain with modifications a sliding scale fee based on construction costs. One suggested the Commission impose no fee for projects costs in excess of $100,000,000. The others suggested the Commission adopt a rate that decreases as investment levels increase. In this proposal, we have taken an entirely different approach by imposing processing fees on a much wider range of applications.

C. *Annual or quarterly billing.*

One commenter proposed that the annual increase in each natural gas company's gross jurisdictional plant be prorated and billed annually according the relative increases of each pipeline. The commenter argued that many companies find it burdensome to file fee checks approximately once every three days with each application or certificate order. Given the magnitude of the ANGTS, this proposal adopts the annual billing approach for the Alaskan sponsors.

D. *Retroactive application.*

Some commenters argued that the fee structure under consideration should be accorded retroactive application, especially when the new rule would impose less fees than the existing fee schedule. One commenter cited *National Association of Broadcasters* v. *F.C.C.,* 554 F.2d 1118 (D.C. Cir., 1976) as requiring that the Commission apply retroactively any modification in its fee schedule.

The proposed rule would apply the new fee schedule prospectively, and for the first time, establish significant processing fees for a variety of applications. Retroactive application of the proposed fee schedule would unfairly impose a substantial economic and administrative burden on those persons who, over the years, relied on the existing regulations. Moreover, because the existing fee structure is valid, justice does not require the proposed fee be applied retroactively to cure any injury suffered by the applicants.

In *National Ass'n of Broadcasters,* the Court of Appeals for the D.C. Circuit held that the Supreme Court's decision in *National Cable Television Association* v. *United States,* 415 U.S. 336 (1974), which invalidated the F.C.C.'s fee schedule, had retroactive effect. In proposing a new fee structure the Commission is making no implicit findings that the existing fee regulations are invalid. The Commission simply seeks to more equitably allocate the economic burden of processing certifcates among a wider variety of applicants.

VI. Summary of Proposed Rule

Section 159.1 currently specifies the $50 filing fee which must accompany applications. The scope of this fee would be expanded to include petitions for rehearing pursuant to section 19 of the Natural Gas Act, applications for declaratory orders, extraordinary relief from curtailment, and determinations under section 25 of the Outer Continental Shelf Lands Act.

Proposed § 159.1(b) would establish a new $1,000 filing fee payable upon the submission of an application in four categories of authorizations. The Commission believes that these four categories of applicants receive a special benefit from the commission processing of their applications. In cases where the Director of Office of Pipeline and Producer and Regulation can dispose of the applications under his delegated authority, no further fees are due.

Section 159.1a provides for additional fees in cases where the certificate application cannot be issued by the Director. The majority of these cases are decided under § 1.32 of the Commission's regulations. For this category, an additional $3,000 fee would be due within 30 days following the issuance of the certificate order. Proposed paragraph (c) divides the $18,500 fee for certificate cases which are set for evidentiary hearing into four payments. The first payment of $1,000 would be made when the application is submitted. Paragraph (c)(1) prescribes an additional $3,000 to be paid within 30 days after the issuance of a hearing order. A third payment of $5,000 would be due within 30 days after the initial decision is issued by the presiding officer, and a fourth payment of $9,500 would be due within 30 days of the issuance of the Commission's certificate order. An additional $50 fee may become due should any of the parties to such a proceeding apply for rehearing. *See* proposed § 159.1(a)(8).

The annual charges assessed natural gas companies under § 159.2a has been discontinued in light of the United States Supreme Court's opinion of *New England Power* v. *FPC*, 415 U.S. 345 (1974). As a result, § 159.2a will be deleted.

Section 159.3 is proposed to be amended in order to clarify the Commission's practice toward waiver and refunds of fees. No fees will be refunded unless the payment of such fee is accompanied by a contemporaneous protest. This requirement is necessary because unprotested fees are deposited in the U.S. Treasury and pass beyond the Commission's jurisdiction. In contrast, fees paid under contemporaneous protest are deposited in a special suspense account in the U.S. Treasury and are subject to further Commission action.

Applications for certificates which are necessary or related to the construction or initial operation of ANGTS are subject to the annual billing procedure specified in proposed § 159.3(e). However, some applications may not be definitely related to ANGTS and uncertainity may surround whether the project is subject to the initial filing fee requirement or the annual billing procedure. In such cases, the application should be accompanied by a request for waiver. If a certificate is subsequently determined to be necessary or related to ANGTS, the fees paid upon filing would be refunded and the processing cost will be reflected in the annual billing procedure.

VII. Written Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, on or before September 4, 1981. Each person submitting a comment should indicate that the comments are being submitted in Docket No. RM79–63, and should give reasons, including any supporting data, for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be

addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE, Washington, D.C., during business hours.

[Department of Energy Organization Act, 42 U.S.C. sections 7101 *et seq.*; E.O. 12009, 42 FR 46267; Independent Offices Appropriations Act, 31 U.S. section 483a; Natural Gas Act, 15 U.S.C. sections 717–717w]

In consideration of the foregoing, the Commission proposes to amend Part 159, Chapter I, Title 18, Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 159—FEES AND ANNUAL CHARGES UNDER THE NATURAL GAS ACT AND RELATED AUTHORITIES

1. The title of Part 159 shall be amended to read "Fees Under the Natural Gas Act and Related Authorities".

2. Section 159.1 is revised to read as follows:

§ 159.1 Filing fees to accompany application.

(a) A filing fee of $50 shall accompany each:

(1) Application for an exemption under section 1(c) of the Natural Gas Act;

(2) Application to import or export natural gas under section 3 of the Natural Gas Act;

(3) Application for a permit under Executive Order 10485;

(4) Application for permission and approval to abandon under section 7(b) of the Natural Gas Act;

(5) Application for a determination by the Commission under sections 5 or 25 of the Outer Continental Shelf Lands Act (43 U.S.C. sections 1334 and 1351);

(6) Application for a declaratory order, or extraordinary relief from curtailment under the Natural Gas Act;

(7) Application for rehearing pursuant to section 19 of the Natural Gas Act of any order acting upon any of the applications listed in this section;

(8) Amendment to any of the applications listed in this section and those referred to in § 159.3(c).

(b) A filing fee of $1,000 shall accompany each:

(1) Application or petition to intervene in a proceeding in which the applicant or petitioner is requesting an order under section 7(a) of the Natural Gas Act;

(2) Application filed by any person (other than an independent producer) for a certificate of public convenience and necessity under section 7(c) and (e) of the Natural Gas Act;

(3) Application for a transportation authorization under section 311(a) of the Natural Gas Policy Act of 1978, filed pursuant to § 284.107 or § 284.127 of this chapter.

(4) Applications for authorization of an assignment under section 312 of the Natural Gas Policy Act of 1978, filed pursuant to §284.165(a) of this chapter.

3. A new § 159.1a is added to read as follows:

§ 159.1a Other Processing Fees.

(a) *Applicability.* The fees prescribed by this section shall apply to the processing of applications or amendments, except for those filed by independent producers or which are determined by the Commission to be necessary or related to the construction and initial operation of the Alaska Natural Gas Transportation System.

(b) *Statutory hearing orders.* Within 30 days following the issuance of a certificate of public convenience and necessity, a $3,000 fee shall be paid, unless;

(1) the certificate was issued by the Director of the Office of Pipeline and Producer Regulation pursuant to § 375.307 of this chapter; or

(2) the proceeding was set for evidentiary hearing (in which case paragraph (c) of this section shall apply).

(c) *Evidentiary hearings.* The applicant for a certificate of public convenience and necessity which has been set for full or limited evidentiary hearing shall pay:

(1) $3.000, within 30 days after the issuance of an order setting the matter for hearing;

(2) $5,000, within 30 days after the issuance of an initial decision by the presiding officer;

(3) $9,500, within 30 days after the issuance of an order by the Commission subsequent an initial decision.

4. Section 159.2 is amended by revising the introductory language, and adding a new paragraph (f), to read as follows:

§ 159.2 Applications involving construction or acquisition of facilities.

In addition to the fees prescribed by § 159.1, and except as provided in paragraphs (e) and (f) of this section, applicants for certificates of public convenience and necessity shall pay the following fees on applications or amendments filed prior to October 1, 1981:

* * * * *

(f) *Exlusions.* This section does not apply to facilities determined by the Commission to be necessary or related to the construction or initial operation of the Alaska Natural Gas Transportation System.

§ 159.2a [Removed].

5. Part 159 is amended by removing § 159.2a, in its entirety.

6. Section 159.3 is amended by revising paragraphs (a) and (b), and by adding new paragraph (e) and (f), to read as follows:

§ 159.3 Miscellaneous.

(a) *Method of payment.* Fee payments shall be made by check or money order payable to the Treasurer of the United States. The docket number of the proceeding should be indicated on the check or money order.

(b) *Exemptions.* The fees prescribed in §§ 159.1 and 159.1a do not apply to:

(1) authorizations sought by independent producers as defined in § 154.91(a) of this chapter, or

(2) applications for certificate of public convenience and necessity determined by the Commission to be necessary or related to the construction and initial operation of the Alaska Natural Gas Transportation System.

* * * * *

(e) *Alaska Natural Gas Transportation System.* The Secretary shall annually bill applicants for certiciates of public convenience and necessity which are necessary or related to the construction and initial operation of the Alaska Natural Gas Transportation System a fee which is fair and equitable taking into consideration the direct and indirect cost to the Government for the processing of the applications. The fee shall recover the annual direct costs of the Alaska Natural Gas Project Office, the Staff efforts of other offices devoted to the processing of such applications, and associated overhead costs.

(f) *Refunds and waivers.* (1) If an application or amendment is determined by the Commission to be necessary or related to the construction and initial operation of the Alaska Natural Gas Transportation System subsequent to the payment of a fee, the applicant may petition the Commission for a refund.

(2) No fee will be refunded unless the applicant submits a written protest of the assessment of the fee at the time that the fee is paid.

(3) At the time that an application is filed with the Commission, or a fee otherwise becomes due, the applicant may request a waiver of a fee prescribed in this part pursuant to § 1.7 of this chapter. The processing of the application shall be held in abeyance pending disposition of the waiver request. The acceptance by the Treasurer of a partial payment of a fee does not constitute waiver of the remainder.

¶ 32,153 High-Cost Gas Produced From Tight Formations (Colorado-14)

46 F. R. 43843 (September 1, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado—14)]

High-Cost Gas Produced From Tight Formations; Colorado

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission has determined that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of Pipeline and Producer Regulation contains the amended recommendation of the Colorado Oil and Gas Conservation Commission that the Dakota Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on September 24, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on September 9, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie J. Lawner, (202) 357-8307 or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

Issued: August 25, 1981.

On May 4, 1981, a Notice of Proposed Rulemaking was issued to determine whether to adopt a recommendation of the Colorado Oil and Gas Conservation Commission (Colorado) that the Dakota Formation in Mesa and Garfield Counties, Colorado, be designated as a tight formation pursuant to § 271.703 of the Commission's regulations. This original Notice of Proposed Rulemaking appeared in the Federal Register on May 8, 1981 (46 FR 25643). One comment was received in response to the Notice in support of the recommendation.

On August 11, 1981, Colorado filed an amendment to its recommendation that the Dakota Formation be designated as a tight formation. The amendment contained additional data to support its recommendation. The amendment further sought to delete all of Sections 15, 16 and 22, Township 9 South, Range 100 West, 6th P.M., from the recommended area, inasmuch as expected production from wells completed in these sections, which are on the fringe of the recommended area, would be in excess of the production guideline found in § 271.703(c)(2)(i)(B).

The instant Notice of Proposed Rulemaking is issued to afford notice of, and an opportunity for comment on, the deletion of the above-described sections from Colorado's recommendation that the Dakota Formation be designated as a tight formation. Colorado's amended recommendation and supporting data are on file with the Commission and are available for public inspection.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Dakota Formation, as described and delineated in Colorado's

recommendation as amended and filed with the Commission, be designated as a tight formation pursuant to § 271.703.

Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E. Washington, D.C. 20426 on or before September 24, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Colorado—14), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than September 9, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

PART 271—CEILING PRICES

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703(d) is amended by adding new subparagraph (64) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(64) *Dakota Formation in Colorado.* RM79-76 (Colorado—14).

(i) *Delineation of formation.* The Dakota Formation is found in Mesa and Garfield Counties, Colorado, and consists of all or portions of Townships 7 through 11 South, Ranges 96 through 100 West, 6th P.M.

(ii) *Depth.* The Dakota Formation occurs at an average measured depth of 7075 feet.

* * * * *

¶ 32,154 High-Cost Gas Produced From Tight Formations (New Mexico-5)

46 F. R. 43884 (September 1, 1981); 46 F. R. 48235 (October 1, 1981).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-5)]

High-Cost Gas Produced From Tight Formations; New Mexico

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of New Mexico and the United States Geological Survey that the Mesaverde Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on September 24, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on September 9, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

Issued: August 25, 1981.

I. Background

On July 30, 1981, the State of New Mexico Oil Conservation Division (New Mexico) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Mesaverde Formation located in Rio Arriba County, New Mexico, be designated as a tight formation. The United States Geological Survey (USGS) concurs with New Mexico's recommendation, however, the USGS recommends the addition of contiguous acreage, thereby enlarging the area recommended by New Mexico. The New Mexico and USGS recommendations and supporting data are on file with the Commission and are available for public inspection. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New Mexico's recommendation that certain portions of the Mesaverde Formation be designated a tight formation should be adopted and whether the USGS recommendation to include contiguous acreage should also be adopted.

II. Description of Recommendation

The Mesaverde Formation is located in Rio Arriba County, New Mexico, approximately 30 miles south of Dulce, New Mexico. The area recommended by New Mexico and the USGS is situated in Townships 26, 27 and 28 North, Ranges 2 and 3 West, along the eastern fringe of the main Blanco Mesaverde Gas Pool. The specified area is almost 11 miles in length and 4 miles in width. The Mesaverde Formation consists of two 40 to 100 feet thick sand members, the Cliff House and Point Lookout Sand-

stones, separated by about 300 feet of the Menefee shale member. The average depth to the top of the Mesaverde Formation is 5,563 feet. The recommended area is subject to New Mexico Order No. R-1670-T, issued November 14, 1974, which authorizes infill drilling in the Blanco Mesaverde field. Accordingly, certain portions within the proposed area may be subject to exclusion pursuant to § 271.703(c)(2)(i)(D) of the regulations.

III. Discussion of Recommendation

New Mexico claims in its submission that evidence gathered through information and testimony presented at a public hearing in Case No. 7154 convened by New Mexico on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

New Mexico further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by New Mexico and the USGS that the Mesaverde Formation, as described and delineated in New Mexico's and the USGS recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capital Street NE., Washington, D.C. 20426, on or before September 24, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (New Mexico—5), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than September 9, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event New Mexico's and the USGS recommendation is adopted.

Kenneth A. Williams,
Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (63) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

[48] through [62] [Reserved]

[63] *Mesaverde Formation in New Mexico.* RM79–76 (New Mexico—5).

(i) *Delineation of formation.* The Mesaverde Formation underlies portions of Townships 26, 27 and 28 North, Ranges 2 and 3 West, in Rio Arriba County, New Mexico. The proposed area is within the Blanco Mesaverde Gas Pool approximately 30 miles south of Dulce, New Mexico. It consists of the Cliff House and Point Lookout sandstone members, separated by the Menefee shale member.

(ii) *Depth.* The Mesaverde Formation is overlain by the Lewis Shale Formation and underlain by the Mancos Shale Formation. The average depth to the top of the Mesaverde Formation is 5,563 feet.

* * * * *

¶ 32,155 High-Cost Gas Produced From Tight Formations (Oklahoma-1)

46 F. R. 43845 (September 1, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Oklahoma—1)]

High-cost Gas Produced From Tight Formations; Oklahoma

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Oklahoma that the Atoka formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on September 24, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on September 9, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or John R. Johnson (202) 357–8731.

SUPPLEMENTARY INFORMATION:

Issued: August 25, 1981.

I. Background

On July 20, 1981, the State of Oklahoma Corporation Commission (Oklahoma) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Atoka formation located in Washita County, Oklahoma, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Oklahoma's recommendation that the Atoka formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Oklahoma's recommendation. Oklahoma's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Oklahoma recommends that the Atoka formation located in Western Oklahoma in the Anadarko Basin area approximately 60 miles west of Oklahoma City, Oklahoma, be designated as a tight formation. The present estimated areal extent is 40,320 acres and is located in the northeast corner of Washita County within townships 9N–14W, 10N–14W, 9N–15W, 10N–15W, 10N–16W, and 11N–16W.

The Stratigraphic location of the Atoka formation is described as the uppermost sandstone development in the Atokan Series of the Lower Pennsylvanian System which underlies the Cherokee/Red Fork Group and overlies the post-13 Finger Lime shale. The average depth to the top of the formation is approximately 14,800 feet. The average net productive interval is approximately 40 feet.

III. Discussion of Recommendation

Oklahoma claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause U.S. No. 9813, Order No. 193998 convened by Oklahoma on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day. Oklahoma further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Oklahoma that the Atoka formation, as described and delineated in Oklahoma's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before September 24, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Oklahoma—1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commmission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than September 9, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Oklahoma's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulations.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (62) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(48) through (61) [Reserved]

(62) *Atoka Formation in Oklahoma.* RM79-76 (Oklahoma—1).

(i) *Delineation of formation.* The Atoka formation is found in Washita County, Oklahoma, in Township 9 North, Range 14 West, Sections 2 through 11; Township 9 North, Range 15 West, Sections 1 through 3, 11 and 12; Township 10 North, Range 14 West, Section 5 through 8, 17 through 21, and 27 through 35; Township 10 North, Range 15 West, Sections 6 through 30, 33 through 36; Township 10 North, Range 16 West, Sections 1 through 5, 8 through 14, 24 and 25; Township 11 North, Range 16 West, Sections 16, 20 through 22, 27 through 29, and 32 through 35.

(ii) *Depth.* The Atoka formation is defined as the uppermost sandstone development in the Atoka Series of the Lower Pennsylvanian System which underlies the Cherokee/Red Fork Group and overlies the post-13 Finger Lime shale. The average depth to the Atoka formation is approximately 14,800 feet.

. . . . .

¶ 32,156 High-Cost Gas Produced From Tight Formations (Texas-1—Addition)

46 F. R. 43847 (September 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas—1 Addition)]

High-Cost Gas Produced From Tight Formations; Texas

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that an additional area of the Cotton Valley Sandstone be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on September 24, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on September 9, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Issued: August 25, 1981.

I. Background

On July 17, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that an additional area of the Cotton Valley Sandstone located in the area of the Paige, N.E. Field, in the eastern portion of Bastrop County, be designated as a tight formation. The Commission previously adopted a recommendation that the Cotton Valley Group found in the northeastern part of the State of Texas, underlying 48 counties in Railroad Commission Districts 1, 3, 5 and 6, be designated as a tight formation (RM79-76 Texas—1, Order No. 105 issued October 24, 1980). Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hearby issued to determine whether Texas' recommendation that the Cotton Valley Sandstone in the Paige, N.E. Field area be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Cotton Valley Sandstone in the Paige, N.E. Field area, encountered in the eastern portion of Bastrop County, Texas, Railroad Commission District 1, be designated as a tight formation. The boundaries of the recommended area are approximately 2.5 miles around the Hou-Tex Oil and Gas Co., No. 1 O.R. Mitchell well in the Paige N.E. (Cotton Valley) Field. This well discovered the Paige, N.E. Field

located 2 miles from Paige, Texas in the Wm. Boatwright Survey, A–82. The depositional environment of the Cotton Valley Sands is believed to be a deltaic fan deposit with no definite strike, trending toward the coast of Texas.

In the type well the formation is shown to occur from 11,820 feet to a total depth of 12,780 feet. In a nearby well the gross thickness is 1,790 feet.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Cotton Valley Sandstone in the Paige, N.E. Field area, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before September 24, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Texas—1 Addition), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than September 9, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,
Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) subparagraph (1) is revised to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(1) *The Cotton Valley Group in Texas.* RM79–76 (Texas—1).

(i) *The Cottom Valley Group consists of the Cotton Valley Sandstone, the Bossier Shale and the Cotton Valley Lime Formations.*—(A) *Delineation of formation.* The northern boundary of the Cotton Valley Group is the Texas-Oklahoma border extending through Fannin, Lamar, and Red River Counties; the eastern boundary is formed by the Texas-Arkansas and Texas-Louisiana borders; the southern boundary is along the Angelina-Caldwell flexure running through Sabine, San Augustine, Angelina and Trinity Counties; the western boundary is set by the Mexia-Talco fault zone through Limestone, Navarro, and Kaufman Counties.

(B) *Depth.* Cotton Valley Sandstone is encountered at an average depth of approximately 7,000 feet to the north, 8,000 feet to the east, between 10,000 feet and 11,000 feet to the south, and 5,000 feet to the west; Bossier Shale is encountered at 7,700 feet to the north, 10,720 feet to the east, 12,600 feet to the south, and 5,340 feet to the west; Cotton Valley Lime is encountered at 8,000 feet to the north, 11,400 feet to the east, 13,200 feet to the south, and 5,500 feet to the west.

(ii) *The Cotton Valley Sandstone in the Paige, N.E. Field Area.*—(A) *Delineation of formation.* The Cotton Valley Sandstone in the Paige, N.E. Field area is found in the eastern portion of Bastrop County, Texas, Railroad Commission District 1. The boundaries of the recommended area are approximately 2.5 miles around the Hou-Tex Oil and Gas, No. 1 O.R. Mitchell well. This well discovered the Paige, N.E. Field located 2 miles from Paige, Texas in the Wm. Boatwright Survey, A–82.

(B) *Depths.* The top and base of the Cotton Valley Sandstone are found at the approximately subsea depths of—11,520 feet and—12,780 feet, respectively. The maximum thickness of the formation is approximately 1,790 feet.

* * * * *

¶ 32,157 High-Cost Gas From Produced Tight Formations (Colorado-16)

46 F. R. 45155 (September 10, 1981).

18 CFR Part 271

[Docket No. RM79-76 Colorado-16)]

High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission; Energy.

ACTION: Notice proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado that the Sussex Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on October 5, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on September 21, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:
Issued: September 4, 1981.

I. Background

On August 28, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Sussex Formation located in Weld County, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Sussex Formation be designated a tight formation should be adopted. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies certain lands in Weld County, Colorado, between the towns of Gilcrest and La Salle. The recommended area consists of Township 4 North, Range 66 West, 6th P.M., Sections 2, 3, and 10, Section 11–N 1/2. Section 15–W½; Township 5 North, Range 66 West, 6th P.M., Sections 33, 34, and 35. There is no Federal land within the recommended area. The Sussex pay zone is usually found at a depth of 4,400 to 4,500 feet.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–20 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells

completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 *FR* 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Sussex Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before October 5, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Colorado-16), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than September 21, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (65) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(48) through (64) [Reserved]

(65) *Sussex Formation in Colorado.* RM79-76 (Colorado-16).

(i) Delineation of formation. The Sussex Formation is found in Weld County, Colorado, in Township 4 North, Range 66 West, 6th P.M., Sections, 2, 3, and 10, Section 11-N ½, Section 15-W½; Township 5 North, Range 66 West, 6th P.M., Sections 33, 34, and 35.

(ii) *Depth.* The average depth to the top of the Sussex Formation is between 4,400 and 4,500 feet.

¶ 32,158 High-Cost Gas Produced From Tight Formations (Utah-4)

46 F. R. 46142 (September 17, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Utah-4)]

High-Cost Gas Produced from Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 C.F.R. § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Utah that the Morrison Formation be designated as a tight formation under § 271.703(d).

DATES: Comments on the proposed rule are due on October 13, 1981.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on September 28, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION: In the matter of high-cost gas produced from tight formations, Docket No. RM79-76, (Utah-4), notice of proposed rulemaking by Director, OPPR.

Issued: September 11, 1981.

I. Background

On August 31, 1981, the State of Utah Board of Oil, Gas, and Mining, (Utah) and the United States Geological Survey submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Morrison Formation located in Grand and Uintah Counties, Utah, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Utah's recommendation that the Morrison Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Utah's recommendation. Utah's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlines certain lands in the Book Cliffs area of Grand and Uintah Counties, Utah, just north of the town of Thompson. The recommended area contains 550,860 acres located in the general area of Townships 15 South through 20 South and Ranges 17 East through 24 East. The average depth to the top of the Morrison Formation is 6,315 feet. The gross production interval averages approximately 600 feet in thickness.

III. Discussion of Recommendation

Utah claims in its submission that evidence gathered through information

and testimony presented at a public hearing in Cause No. TGF-103 convened by Utah on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Utah further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Utah that the Morrison Formation, as described and delineated in Utah's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before October 13, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Utah-4), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such requests shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than September 28, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Chapter I Title 18, Code of Federal Regulations, as set forth below, in the event Utah's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(64) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(48) through (63) [Reserved]

(64) *Morrison Formation in Utah.* RM79-76 (Utah-4).

(i) *Delineation of formation.* The Morrison Formation is found in the Book Cliffs area of Grand and Uintah Counties, Utah, and is in the general area of Townships 15 South, through 20 South and Ranges 17 East through 24 East.

(ii) *Depth.* The average depth to the top of the Morrison Formation is 6,315 feet.

¶ 32,159 High-Cost Gas Produced From Tight Formations (Colorado-17)

46 F. R. 47239 (September 25, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-17)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

Issued: September 21, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado that the Mesaverde Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on October 21, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 6, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

I. Background

On September 10, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Mesaverde Formation located in Garfield County, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Mesaverde Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies 96,612 acres in the Grand Valley Area of Garfield County, Colorado, between the towns of Debeque, and Rifle, Colorado. It is defined as being between the base of the Wasatch Formation (Tertiary) and the top of the Mancos shale, with an average depth to the top of the formation of 4,475 feet. The acreage included in the recommended area is 64% Fee, 31.1% Federal, and 4.8% Naval Oil Shale Leaseholds. Exact location for the recommended area is as follows: Township 6 South, Range 93 West, 6th P.M., Sections 3 through 10, 15 through 22, 27 through 34; Township 6 South, Range 94 West, 6th P.M., Sections 1 through 3, 7 through 36; Township 6 South, Range 95 West, 6th P.M., Sections

25 through 36; Township 7 South, Range 94 West, 6th P.M., Sections 1 through 9, 16 through 18; Township 7 South, Range 95 West, 6th P.M., Sections 1 through 24, 27 through 34; Township 7 South, Range 96 West, 6th P.M., Sections 1 through 36; Township 8 South, Range 96 West, 6th P.M., Sections 1 through 6.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–21 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Mesaverde Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before October 21, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–17), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 6, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3342.)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new paragraph (66) as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as

tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(55) through (65) [Reserved]

(66) *Mesaverde Formation in Colorado.* RM79–76 (Colorado–17).

(i) *Delineation of formation.* The Mesaverde Formation is found in Garfield County, Colorado, in Township 6 South, Range 93 West, 6th P.M., Sections 3 through 10, 15 through 22, 27 through 34; Township 6 South, Range 94 West, 6th P.M., Sections 1 through 3, 7 through 36; Township 6 South, Range 95 West, 6th P.M., Sections 25 through 36; Township 7 South, Range 94 West 6th P.M., Sections 1 through 9, 16 through 18; Township 7 South, Range 95 West, 6th P.M., Sections 1 through 24, 27 through 34; Township 7 South, Range 96 West, 6th P.M., Sections 1 through 36; Township 8 South, Range 96 West, 6th P.M., Sections 1 through 6.

(ii) *Depth.* The Mesaverde Formation is defined as being between the base of the Wasatch Formation (Tertiary) and the top of the Mancos shale. The average depth to the top of the Mesaverde Formation is 4,475 feet.

¶ 32,160 High-Cost Gas Produced From Tight Formations (New Mexico-6)

46 F. R. 47466 (September 28, 1981).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-6)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of New Mexico that the Dakota Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on October 22, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 7, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

Issued: September 22, 1981.

I. Background

On September 2, 1981, the State of New Mexico Oil Conservation Division (New Mexico) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Dakota Formation located in San Juan and Rio Arriba Counties New Mexico, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New Mexico's recommendation that the Dakota Formation be designated a tight formation should be adopted. New Mexico's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The Dakota Formation is located in San Juan and Rio Arriba Counties, New Mexico. The area recommended by New Mexico is situated generally in Townships 24 and 25 North, Ranges 7 through 10 West NMPM. The Dakota Formation underlies the described land and contains approximately 135,040 acres. The average depth to the top of the Dakota Formation is 6,350 feet and the thickness of such formation varies from 200 to 350 feet. The recommended area is subject to New Mexico Order No. R-1670-V, issued May 22, 1979, which authorizes infill drilling in the Basin Dakota Gas Pool. The Basin Dakota Gas Pool contains the recommended formation. Accordingly, certain portions within the proposed

area may be subject to exclusion pursuant to § 271.703(c)(2)(i)(D) of the regulations.

III. Discussion of Recommendation

New Mexico claims in its submission that evidence gathered through information and testimony presented at a public hearing in Case No. 7252 convened by New Mexico on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

New Mexico further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by New Mexico that the Dakota Formation, as described and delineated in New Mexico's reommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before October 22, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (New Mexico-6), and should give reasons including supporting data for any recommendatons. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE, Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 7, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Title 18, Code of Federal Regulations, as set forth below, in the event New Mexico's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (67) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of

the jurisdictional agency that submitted the recommendation.

• • • • •

(55) through (66) [RESERVED]

(67) *Dakota Formation in New Mexico.* RM79–76 (New Mexico—6).

(i) *Delineation of formation.* The Dakota Formation underlies portions of Townships 24 and 25 North, Ranges 7 through 10 West, in San Juan and Rio Arriba Counties, New Mexico. The State of New Mexico has defined the Dakota producing interval in the Basin Dakota Field to begin at the base of the Greenhorn Limestone and extend to a point 400 feet below the base of the Greenhorn Limestone.

(ii) *Depth.* The average depth to the top of the Dakota Formation is 6,350 feet. The Dakota Formation begins at the base of the Greenhorn Limestone and is 200 to 350 feet in gross thickness.

¶ 32,161 High-Cost Gas Produced From Tight Formations (Utah-3)

46 F. R. 48234 (October 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Utah-3)]

High-Cost Gas Produced from Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Utah that the Dakota Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on October 28, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket at yet. Written requests for a public hearing are due on October 13, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

Issued: September 28, 1981.

I. Background

On August 31, 1981, the State of Utah Board of Oil, Gas, and Mining (Utah), submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Dakota Formation located in Grand and Uintah Counties, Utah, be designated as a tight formation. The United States Geological Survey joined in Utah's recommendation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Utah's recommendation that the Dakota Formation be designated as a tight formation should be adopted. Utah's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies certain lands in the Book Cliffs area of Grand and Uinatah Counties, Utah, just north of the town of Thompson. The recommended are contains 550,860 acres located in the general area of Townships 15 South through 20 South, and Ranges 16 East through 24 East. The average depth to the top of the Dakota Formation is 6,034 feet. The average thickness of the Dakota Formation measured from the top of the Dakota Silt down to the top of the Morrison Formation is approximately 250 feet.

III. Discussion of Recommendation

Utah claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. TGF-102 convened

by Utah on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) "The standard production of gas from the subject lands, without stimulation, does not exceed the rate established by the Federal Energy Regulatory Commission (§ 271.703(c)(2)(i)(B)), taking into proper account the average depth from the surface to the Dakota Formation and the cost of drilling and completing gas wells in the area;" and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Section 271.703(c)(2)(i) states that the Commission will approve the designation of any formation recommended by a jurisdictional agency if the formation meets each of the guidelines set forth in § 271.703(c)(2)(i)(A), (B), (C) and (D. Preliminary Commission staff analysis indicated that Utah's recommendation may not meet the guideline specified in § 271.703(c)(2)(i)(B) because the staff computation based on data submitted in support of the recommendation reflects an average pre-stimulation flow rate of wells completed for production in the recommended formation in excess of the maximum allowable production rate set out in the regulation. Comments are specifically requested on this issue.

Utah further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Utah that the Dakota Formation, as described and delineated in Utah's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

Federal Energy Regulatory Commission

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before October 28, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Utah-3), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 13, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342.)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Title 18, Code of Federal Regulations, as set forth below, in the event Utah's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (63) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(55) through (62) [RESERVED.]

(63) *Dakota Formation in Utah.* RM79–76 (Utah–3).

(i) *Delineation of formation.* The Dakota Formation is found in the Book Cliffs area of Grand and Uintah Counties, Utah and is in the general area of Townships 15 South through 20 South and Ranges 16 East through 24 East. The Dakota Formation is defined as the interval from the top of the Dakota Silt down to the top of the Morrison Formation, a thickness of approximately 250 feet.

(ii) *Depth.* The average depth to the top of the Dakota Formation is 6,034 feet.

¶ 32,162 High-Cost Gas Produced From Tight Formations (New Mexico-7)

46 F. R. 50085 (October 9, 1981).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-7)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of New Mexico that the Pictured Cliffs Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 2, 1981.

Public hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

Issued October 2, 1981.

SUPPLEMENTARY INFORMATION:

I. Background

On September 16, 1981, the State of New Mexico Oil Conservation Division (New Mexico) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 F.R. 56034, August 22, 1980), that the Pictured Cliffs Formation located in San Juan and Rio Arriba Counties, New Mexico, be designated as a tight formation.

Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New Mexico's recommendation that the Pictured Cliffs Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with New Mexico's recommendation. New Mexico's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies certain lands in San Juan and Rio Arriba Counties, New Mexico, and is located on the northeast flank of the San Juan Basin of northwest New Mexico. The recommended area contains approximately 33,500 acres within portions of Townships 30 and 31 North, Ranges 7 and 8 West, and Township 31 North, Range 6 West, NMPM.

The recommended formation ranges in thickness from 150 to 250 feet. The average depth to the top of the formation is approximately 3,200 feet.

III. Discussion of Recommendation

New Mexico claims in its submission that evidence gathered through information and testimony presented at a public hearing in Case No. 7086 convened by New Mexico on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

New Mexico further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by New Mexico that the Pictured Cliffs Formation, as described and delineated in New Mexico's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before November 2, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (New Mexico-7), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, in the event New Mexico's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (69) to read as follows:

§ 271.703 **Tight formations.**

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of

the jurisdictional agency that submitted the recommentation.

• • • • •

(55) through (68) [Reserved]

(69) *Pictured Cliffs Formation in New Mexico.* RM79–76 (New Mexico–7).

(i) *Delineation of formation.* The Pictured Cliffs Formation is found in the San Juan Basin and underlies portions of Townships 30 and 31 North, Ranges 7 and 8 West, and Township 31 North, Range 6 West, NMPM, in San Juan and Rio Arriba Counties, New Mexico.

(ii) *Depth.* The average depth to the top of the Pictured Cliffs Formation is approximately 3,200 feet. The thickness of the Pictured Cliffs Formation ranges from 150 to 250 feet.

¶ 32,163 High-Cost Gas Produced From Tight Formations (Colorado-18)

46 F. R. 50563 (October 14, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-18)]

Colorado; High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commision determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formation as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado that the Dakota Formation be designated as a tight formation under § 271.703(d)

DATE: Comments on the proposed rule are due on November 9, 1981.

Public hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 23, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

I. Background

In the matter of high-cost gas produced from tight formations; Docket No. RM79-76 (Colorado-18); notice of proposed rulemaking by Director, OPPR, Issued October 8, 1981.

On September 15, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Dakota Formation located in La Plata and Archuleta Counties, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Dakota Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The Dakota Formation is located in La Plata and Archuleta Counties, Colorado, in Townships 32, 33, and 34 North (South of Ute Line), Ranges 6 through 11 West, NMPM, on the northern flank of the San Juan Basin, in the Ignacio-Blanco Field within the Southern Ute Indian Reservation. The average depth to the top of the Dakota Formation is 7,950 feet. The formation is approximately 225 to 250 feet in thickness. The recommended area is subject to Colorado Order No. 112-46, issued July 16, 1979, which authorizes infill drilling in the Ignacio-Blanco Field. Accordingly,

certain portions within the proposed area may be subject to exclusion pursuant to § 271.703(c)(2)(i)(D) of the regulations.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–23 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Dakota Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 9, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–18), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 23, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703 is amended by adding new paragraph (d)(70) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of

the jurisdictional agency that submitted the recommendation.

* * * * *

(56) through (69) [reserved]

(70) *Dakota Formation in Colorado.* RM79-76 (Colorado-18).

(i) *Delineation of formation.* The Dakota Formation underlies portions of Townships 32, 33, and 34 North (South of Ute Line), Ranges 6 through 11 West, in La Plata and Archuleta Counties, Colorado, and it is within the Ignacio-Blanco Field.

(ii) *Depth.* The Dakota Formation is below the Graneros Shale and above the Morrison Formation. The average depth to the top of the Dakota Formation is 7,950 feet. The formation is approximately 225 to 250 feet in thickness.

¶ 32,164 High-Cost Gas Produced From Tight Formations (Colorado-19)

46 F. R. 50564 (October 14, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-19)]

Colorado; High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado that the Mesaverde Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 9, 1981.

Public hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 23, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

I. Background

In the matter of high-cost gas produced from tight formations; Docket No. RM79-76 (Colorado-19); notice of proposed rulemaking by Director, OPPR (Issued October 8, 1981).

On September 15, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Mesaverde Formation located in La Plata and Archuleta Counties, Colorado be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Mesaverde Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The Mesaverde Formation is located in LaPlata and Archuleta Counties, Colorado, in Townships 32, 33, and 34 North (South of Ute Line), Ranges 6 through 11 West, NMPM, on the northern flank of the San Juan Basin, in the Ignacio-Blanco Field within the Southern Ute Indian Reservation. The average depth of the top of the Mesaverde Formation is 5,380 feet. The formation is approximately 900 feet in thickness. The recommended area is subject to Colorado Order No. 112-46, issued July 16, 1979, which authorizes

infill drilling in the Ignacio-Blanco Field. Accordingly, certain portions within the proposed area may be subject to exclusion pursuant to § 271.703(c)(2)(i)(D) of the regulations.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–24 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Mesaverde Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 9, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–19) and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 23, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703 is amended by adding new paragraph (d)(71) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated.

and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(71) *Mesaverde Formation in Colorado.* RM79–76 (Colorado–19).

(i) *Delineation of formation.* The Mesaverde Formation underlies portions of Townships 32, 33, and 34 North (South of Ute Line), Ranges 6 through 11 West, in La Plata and Archuleta Counties, Colorado. The formation is within the Ignacio-Blanco Field.

(ii) *Depth.* The Mesaverde Formation is below the Lewis Shale Formation and above the Mancos Shale Formation. The average depth to the top of the Mesaverde Formation is 5,380 feet. The formation is approximately 900 feet in thickness.

¶ 32,165 High-Cost Gas Produced From Tight Formations (Texas-13)

46 F. R. 51617 (October 21, 1981).

18 CFR Part 271

[Docket No. RM 79-76 (Texas-13)]

High-Cost Gas Produced From Tight Formations; Texas

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendations of the Texas Railroad Commission that the Navarro Formation be designated as a tight formation under § 271.703(d).

DATES: Comments on the proposed rule are due on November 16, 1981. No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 30, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION: Issued October 15, 1981.

I. Background

On August 25, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's final regulations (45 FR 56034, August 22, 1980), that the Navarro Formation in the Laredo Field, located in the southwestern part of the State of Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Navarro Formation in the Laredo Field be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Navarro Formation in the Laredo Field, encountered in Webb County, Texas, Railroad Commission District 4, be designated as a tight formation. The particular area being recommended is located in the southwestern corner of Webb County, Texas, and consists of an area located within the Laredo (Navarro) Field with the exception of the area surrounding four wells in the extreme northern portion of the field.

The Navarro Formation consists of sandstones that are believed to be marine shelf bar sands. These sands conformably overlie the Taylor formation, of Gulfian Age, and are unconformably overlain by the Kincaid shale of Paleocene Age. The Navarro varies in thickness, reaching a maximum of 28 feet in the D. D. Hachar No. 5 well, as identified in Exhibits 1 and 10. Texas, in Exhibit 10, identifies the top of the Navarro in the D. D. Hachar No. 2 well at −7227 feet (subsea) and the base in

the D. D. Hachar No. 6 well at −7735 feet (subsea).

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regualtions assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM 80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Navarro Formation in the Laredo Field, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, on or before November 16, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM 79-76 (Texas-13), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 30, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (68) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM 79-76, subindexed as indicated, and is also located in the official files of

the jurisdictional agency that submitted the recommendation.

* * * * *

(55) through (67) [Reserved]

(68) *Navarro Formation in the Laredo Field in Texas. RM 79-76 (Texas-13)*—(i) *Delineation of formation.* The Navarro Formation in the Laredo Field is found in Webb County, Texas, Railroad Commission District 4.

(ii) *Depth.* The depth to the top of the Navarro Formation is identified at approximately −7227 feet (subsea) in the northwestern portion of the designated area. The base of the Navarro formation is identified at −7735 feet (subsea) in the southeastern portion of the area. The maximum thickness of the Navarro Formation is approximately 28 feet.

¶ 32,166 High-Cost Gas Produced From Tight Formations (New York-1)

46 F. R. 51618 (October 21, 1981).

18 CFR Part 271

[Docket No. RM 79-76 (New York—1)]

High-Cost Gas Produced From Tight Formations; New York

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive prove (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice is proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of New York that the Medina Group be designated as a tight formation under § 271.703(d).

DATES: Comments on the proposed rule are due on November 16, 1981. No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on October 30, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or John Roy Johnson (202) 357–8731.

SUPPLEMENTARY INFORMATION:

Issued: October 15, 1981.

I. Background

On September 21, 1981, the New York State Department of Environmental Conservation (New York) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Medina Group located in Cattaraugus and Chautauqua Counties, New York, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether New York's recommendation that the Medina Group be designated a tight formation should be adopted. New York's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlines Cattaraugus and Chautauqua Counties, New York, 10 miles south of Buffalo, New York. The proposed area encompasses 2,399 square miles and is bounded by the Pennsylvania state line to the south and west and by Lake Erie to the northwest. The Medina Group is composed of the Grimsby Sandstone, the Power Glen Shale, and the Whirlpool Sandstone and averages a net pay thickness of approximately 55 feet. The average depth to the top of Medina Group is approximately 4,000 feet. The Medina Group is contacted above with the Thorold formation of the Clinton Group and is contacted below with the upper Queenston Shale formation.

III. Discussion of Recommendation

New York claims in its submission that:

(1) The average *in situ* gas permeability throughout the pay section

of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

New York further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM 80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by New York that the Medina Group, as described and delineated in New York's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before November 16, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM 79-76 (New York—1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than October 16, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event New York's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (73) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographic extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM 79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(55) through (72) [Reserved]

(73) *Medina Group in New York. Rm 79-76 (New York—1)*—(i) *Delineation of formation.* The Medina Group is found in Cattaraugus and Chautauqua Counties, New York, and is bounded by Pennylvania to the south and west and by Lake Erie to the northwest. The

Medina Group is defined as the interval contacted above with the Thorold formation and contacted below with the upper Queenston Shale formation, and consists of the Grimsby Sandstone, the Power Glen shale, and the Whirlpool Sandstone.

(ii) *Depth.* The average depth to the top of the Medina Group is 4,000 feet.

The Medina Group averages a net pay thickness of approximately 55 feet.

¶ 32,167 High-Cost Gas Produced From Tight Formations (Colorado-20)

46 F. R. 52126 (October 26, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-20)]

High-Cost Gas Produced From Tight Formations; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado that the Upper Mancos Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 18, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 3, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

Issued: October 19, 1981.

I. Background

On September 25, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Upper Mancos Formation located in Rio Blanco County, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Upper Mancos Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation underlies certain lands in Rio Blanco County, Colorado, and is located in the Southeast Douglas Creek area in the extreme southwest corner of Rio Blanco County. The recommended area contains 69,120 acres within all of Townships 2 and 3 South, Range 100 West, 6th P.M., and the eastern half of Townships 2 and 3 South, Range 101 West, 6th P.M. The acreage included in the recommended area is 92.1% federal, 7.7% fee, and 0.2% state lands.

The recommended formation ranges in thickness from 1,500 to 2,000 feet and is defined as being between the base of the Mesaverde Formation and the top of

the Lower Mancos. The average depth to the top of the formation is 1,800 feet.

III. Discussion of Recommendation

Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–25 convened by Colorado on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Upper Mancos Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 18, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado-20), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 3, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

PART 271—CEILING PRICES

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(72) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* the following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the

designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(72) *Upper Mancos Formation in Colorado.* RM79–76 (Colorado-20).

(i) *Delineation of formation.* The Upper Mancos Formation is found in Rio Blanco County, Colorado, in Townships 2 and 3 South, Range 100 West, 6th P.M., and the eastern half of Townships 2 and 3 South, Range 101 West, 6th P.M.

(ii) *Depth.* The Upper Mancos Formation is defined as being between the base of the Mesaverde Formation and the top of the Lower Mancos Formation. The average depth to the top of the Upper Mancos Formation is 1,800 feet.

¶ 32,168 High-Cost Gas Produced From Tight Formations (Colorado-21)

46 F. R. 52127 (October 26, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-21)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Colorado that the Wasatch Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 18, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 3, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

Issued: October 19, 1981.

I. Background

On September 30, 1981, the State of Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Wasatch Formation located in Garfield County, Colorado, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Colorado's recommendation that the Wasatch Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Colorado's recommendation. Colorado's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located entirely within Garfield County, Colorado, in portions of Township 6 South, Ranges 93 and 94 West, 6th P.M. It is in the Piceance Creek Basin, and the recommended area includes the town of Rifle, Colorado. The recommended area contains 27,703 acres, of which approximately 72 percent is fee acreage and 28 percent is federal land. The average depth to the producing interval is 1,767 feet. The Wasatch formation is defined as all sediments from the surface of the ground down to the top of the Williams Fork and Iles members of the Mesaverde Formation.

III. Discussion of Recommendation

This filing is made pursuant to the alternative designation requirements found at § 271.703(c)(2)(D)(ii) of the Commission's regulations which provides that the Commission may approve a recommendation of a tight formation if the formation is tight, meets the stabilized production rate guideline found in § 271.703(c)(2)(i)(B) and the crude oil production guideline in § 271.703(c)(2)(i)(C), but does not meet the permeability guideline in § 271.703(c)(2)(i)(A), if the jurisdictional agency shows that the incentive price is necessary to provide reasonable incentives for production from that formation. Colorado claims in its submission that evidence gathered through information and testimony presented at a public hearing in Cause No. NG–22 convened by Colorado on this matter demonstrates that:

(1) The recommended formation exhibits low permeability characteristics, and the price established in § 271.703(a) is necessary to provide reasonable incentives for production of gas from the recommended formation.

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Colorado further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Colorado that the Wasatch Formation, as described and delineated in Colorado's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 18, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Colorado–21), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 3, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342)

PART 271—CEILING PRICES

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, in the event Colorado's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(75) to read as follows:

§271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(75) *Wasatch Formation in Colorado.* RM79–76 (Colorado-21).

(i) *Delineation of formation.* The Wasatch Formation is found in Garfield County, Colorado, in Township 6 South, Range 93 West, 6th P.M., Sections 3 through 10, 15 through 22, and 27 through 34, and Township 6 South, Range 94 West, 6th P.M., Sections 1 through 3, 10 through 15, 22 through 27, and 34 through 36.

(ii) *Depth.* The Wasatch Formation extends from the surface of the ground to the top of the Williams Fork and Iles members of the Mesaverde Formation. The average depth to the top of the producing interval of the Wasatch Formation is 1,767 feet.

¶ 32,169 High-Cost Gas Produced From Tight Formations (Louisiana-2 Addition)

46 F. R. 52389 (October 27, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Louisiana—2 Addition)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Louisiana Office of Conservation that an additional area of the Haynesville Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 20, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 5, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Issued: October 21, 1981.

I. Background

On October 1, 1981, the State of Louisiana Office of Conservation (Louisiana) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that an additional area of the Haynesville Formation, located in the northwest part of the state of Louisiana, be designated as a tight formation. The Commission previously adopted a recommendation that the Haynesville Formation adjacent to this additional area be designated as a tight formation (Order No. 141, issued April 29, 1981, in Docket No. RM79-76 (Louisiana—2)). Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Louisiana's recommendation that an additional area of the Haynesville Formation be designated a tight formation should be adopted. Louisiana's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended addition to the Haynesville Formation lies entirely within northern Bossier Parish, on the Arkansas border and is located in the southwestern portion of the Arkana Gas Field. The Haynesville Formation is located below the Bossier Formation and above the Smackover Formation.

The top of the Haynesville Formation is located at a depth of 10,360 feet and the base is located at 10,845 feet on the induction electrical log of the Crystal Oil Company Hall No. 1 Well. In the Arkana Field, the Haynesville Formation consists of three members. The upper member is predominately shale, 120 feet to 220 feet thick; the middle member, the Haynesville Sand, is 120 feet to 220 feet thick with shale stringers varying from 2 feet to 15 feet in thickness; and the lower member, the Buckner, is 200 feet to 400 feet thick, consisting of shale and anhydrite. The area recommended consists of the following sections:

Township 23 North, Range 14 West, sections: 1, 2, 6–10, 15–22, 27–34
Township 23 North, Range 15 West, sections: 1–3, 10–15, 22–27, 34–36

III. Discussion of Recommendation

Louisiana claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Louisiana on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Louisiana further asserts that the requirement of Statewide Order No. 29-B will assure that development of this additional area of the Haynesville Formation will not adversely affect any fresh water aquifer that is or is expected to be used as a domestic or agricultural water supply. Further, Louisiana is in the process of establishing rules and regulations in accordance with the Environmental Protection Agency's Underground Injection Control guidelines which it believes will further prevent the contamination of any fresh water aquifer.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Louisiana that an additional area of the Haynesville Formation as described and delineated in Louisiana's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, on or before November 20, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Louisiana—2 Addition), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE, Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 5, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Louisiana's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by revising subparagraph (22) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, as subindexed below, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(22) *Haynesville Formation in Louisiana.* RM79-76 (Louisiana—2) and (Louisiana—2 Addition)

(i) *Delineation of Formation.*

(A) The Haynesville Formation (Louisiana—2) is found in the northern portion of Bossier Parish, Louisiana, on the Arkansas border and consists of the following: Township 23 North, Range 12 West, Sections 5-8 and 17-19, Township 23 North, Range 13 West, Sections 1-24 and Township 23 North, Range 14 West, Sections 11-14, 23, and 24.

(B) The Haynesville Formation (Louisiana—2 Addition) is a westward extension of the Haynesville formation identified in Louisiana—2 and consists of the following: Township 23 North, Range 14 West, Sections 1 and 2, 6-10, 15-22, and 27-34, and Township 23 North Range 15 West, Sections 1-3, 10-15, 22-27, and 34-36.

(ii) *Depth.* The top of the Haynesville Formation is located at a measured depth of 10,360 feet, with the base located at 10,845 feet on the induction electrical log of the Crystal Oil Company Hall No. 1 Well. In the Arkana Field, the Haynesville Formation consists of three members. The upper member is predominately shale, 120 feet to 220 feet thick; the middle member, the Haynesville Sand, is 120 feet to 220 feet thick, with shale stringers varying from 2 feet to 15 feet in thickness; and the lower member, the Buckner, is 200 feet to 400 feet thick, consisting of shale and anhydrite.

¶ 32,170 High-Cost Gas Produced From Tight Formations (Louisiana-5)

46 F. R. 52390 (October 27, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Louisiana—5)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Louisiana that the Smackover C Zone be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 23, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 6, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556

SUPPLEMENTARY INFORMATION:

Issued: October 22, 1981.

I. Background

On October 5, 1981, the State of Louisiana Office of Conservation (Louisiana) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Smackover C Zone in the East Dykesville Field, located in the northern part of the State of Louisiana, be designated as a tight formation in the Commission's regulations. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Louisiana's recommendation that the Smackover C Zone be designated a tight formation should be adopted. Louisiana's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The Smackover C Zone, underlying specified portions of the East Dykesville Field in Claiborne and Webster Parishes, north Louisiana, is a sandstone interlayered with occasional one to two foot thick beds of shale. The recommended area is described below. It is defined as that formation occurring between the measured depths of 11,290 feet and 11,340 feet on the induction electrical log of the Wheless Industries—Pelto Oil—Guy Lewis et al. No. 1 Well.

Recommended Area

T23N-R8W,
Secs. 30-34.
T22N-R8W,
Secs. 3-10, 15-18.

T23N–R9W,
Secs. 25–27, 34–36.
T22N–R9W,
Secs. 1–3, 10–15.

III. Discussion of Recommendation

Louisiana claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Louisiana on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Louisiana further asserts that existing Statewide Order No. 29–B will assure that development of the Smackover C Zone will not adversely affect any fresh water aquifer that is or is expected to be used as a domestic or agricultural water supply. In addition, Louisiana states that it is in the process of establishing rules and regulations in accordance with the Environmental Protection Agency's Underground Injection Control guidelines which it believes will further prevent the contamination of any fresh water aquifer.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Louisiana that the Smackover C Zone, as described and delineated in Louisiana's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before November 23, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Louisiana—5), and should give reasons, including supporting data, for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing.

Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 6, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Louisiana's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703 is amended by adding new paragraph (d)(76) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geological extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the the jurisdictional agency that submitted the recommendation.

* * * * *

(76) *Smackover C Zone in Louisiana.* RM79–76 (Louisiana—5).

(i) *Delineation of formation.* The Smackover C Zone, a quartz sandstone interlayered with occasional beds of shale, is located in the following portions of Claiborne and Webster Parishes, north Louisiana: T23N–R8W, Sections 30–34; T22N–R8W, Sections 3–10, 15–18; T23N–R9W, Sections 25–27, 34–36; T22N–R9W, Sections 1–3, 10–15.

(ii) *Depth.* The Smackover C Zone is defined as that formation occurring between the measured depths of 11,290 feet and 11,340 feet on the induction electrical log of the Wheless Industrie —Pelto Oil—Guy Lewis et al. No. 1 Well, located in Section 5, Township 22 North, Range 8 West, Claiborne Parish.

¶ 32,171 High-Cost Gas Produced From Tight Formations (Texas-15)

46 F. R. 54384 (November 2, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—15)]

High-Cost Gas Produced From Tight Formations; Texas; Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that the Vicksburg Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on November 27, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 12, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Walter Lawson, (202) 357–8556.

SUPPLEMENTARY INFORMATION:

Issued: October 27, 1981.

I. Background

On Setpember 21, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Vicksburg Formation located in the eastern part of Starr County, Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Vicksburg Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that two areas of the Vicksburg Formation, located in Railroad Commission District 4, in Starr County, Texas, be designated as a tight formation. The first recommended area is located near the Hidalgo County line and is approximately 4.5 miles wide and 6.5 miles long. In this area the Vicksburg Formation consists of an alternating sequence of Oligocene age sands and shales deposited in environments ranging from deltaic to marine. The top of the recommended formation is defined as the "hard geopressure" marker encountered at a depth of approximately −6,000 feet subsea in the south and −8,000 feet subsea in the north. The base of the recommended formation ranges from a depth of −9,500 feet subsea in the west to −12,500 feet subsea in the east, and is defined as the top of the Jackson Shale.

The second recommended area is located in the El Benadito South Field, 2 to 4 miles west of the east Starr County line. The area includes all of Sections 19, 20, 33, and 34 of the G. O. Newman Subivision of Shares 2-A and 2-B El Benadito Grant, A-338 and A-68, encompassing approximately 2,500 acres. In this area the Vicksburg Formation consists of a sequence of thin, very shaley Tertiary Period sands deposited in a deep water environment. In the recommended area, the top of the Vicksburg Formation is defined as the top of the Rincon sand and the base as the top of the Yegua sand. Specifically, it is defined as that interval on the log of the Corpus Christi Oil and Gas Company—Heard #1 Well that occurs between a measured depth of 8,620 feet to 10,837 feet, which yields a gross thickness of 2,217 feet.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates, for each recommended area, that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers that are, or are expected to be, used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Vicksburg Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before November 27, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—15), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 12, 1981.

(Natural Gas Policy Act of 1978 (15 U.S.C. 3301-3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title

18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (77) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM 79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(56) through (76) [Reserved]

(77) *Vicksburg Formation in Texas.* RM79–76 (Texas—15).

(i) *The Vicksburg Formation in Starr County, Texas. (Deep)*—(A) *Delineation of formation.* The Vicksburg Formation is located in Railroad Commission District 4, in the eastern half of Starr County, Texas.

(B) *Depth.* The top of the Vicksburg Formation is defined as the "hard geopressure" marker encountered at a depth of approximately −6,000 feet subsea in the south and −8,000 feet subsea in the north. The base of the Vicksburg Formation ranges from a depth of −9,500 feet subsea in the west to −12,500 feet subsea in the east, and is defined as the top of the Jackson Shale.

(ii) *The Vicksburg Formation in Starr County, Texas. (Lower)*—(A) *Delineation of formation.* The Vicksburg Formation is located in Railroad Commission District 4 in the eastern half of Starr County, Texas.

(B) *Depth.* The top of the Vicksburg formation is defined as the top of the Rincon Sand and the base as the top of the Yegua Sand. Specifically, it is defined as that interval on the log of the Corpus Christi Oil and Gas Company, Heard #1 Well that occurs between a measured depth of 8,620 feet to 10,837 feet, which yields a gross thickness of 2,217 feet.

¶ 32,172 Small Hydroelectric Power Projects With an Installed Capacity of 5 Megawatts or Less; Exemptions From Provisions of Federal Power Act

46 F. R. 55536 (November 10, 1981).

18 CFR Part 4

[Docket No. RM82-2]

Small Hydroelectric Power Projects With an Installed Capacity of 5 Megawatts or Less; Exemptions From Provisions of Federal Power Act

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to amend certain definitions in its regulations governing the exemption of small hydroelectric power projects from provisions of the Federal Power Act to enable diversion projects of a specified size to qualify for exemption on a case-by-case basis as so-called natural water feature projects. The proposed rule would also eliminate notices of intent to file a preliminary permit for such project, if a permit rather than an exemption is sought, and would require a project owner to file for exemption within a specified notice period, if another person previously filed for a permit.

The proposed rule would permit a greater number and variety of projects to be exempted from certain provisions of the Act. The rule would also expedite the filing and consideration of competing applications for exemptible projects.

DATE: Written comments must be filed with the Commission's Secretary by December 7, 1981.

ADDRESS: Comments should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. More information concerning the submittal of comments is found in Supplementary Information.

FOR FURTHER INFORMATION CONTACT:

James Hoecker, Division of Rulemaking and Legislative Analysis, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9342

Ronald Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 376-9171

SUPPLEMENTARY INFORMATION:

October 29, 1981.

The Federal Energy Regulatory Commission (Commission) proposes to amend its regulations which now provide for case-specific exemption of small hydroelectric power projects from certain provisions of Part I of the Federal Power Act (Act), including the licensing provisions. The proposed amendments define the characteristics of certain small hydroelectric power projects, known as natural water feature projects, so as to make specific kinds of projects exemptible under the terms of the Energy Security Act of 1980 (ESA).[1] The Commission may now exempt natural water feature projects under the Commission's procedures established in

[1] Pub. Law 96-294, 94 Stat. 611.

Order No. 106.[2] However, neither the statute nor the regulations define what is meant by a natural water feature other than to state the Commission's authority to exempt projects that utilize natural water features for electric power generation. The Commission proposes to exempt these projects only on a case-specific basis.

The proposed rule would also amend § 4.33 of the Commission's regulations to preclude the filing of notices of intent to file a preliminary permit application, if an application for a permit rather than for an exemption is filed for a natural water feature project. Section 4.104 would also be amended.

I. Natural Water Features

A. Background

The ESA contains a provision that amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to authorize the Commission to exempt certain small hydroelectric power projects, on a case-by-case basis or by class or category of such projects, from all or part of Part I of the Act, including any licensing requirement.[3]

Section 408 of the ESA grants the Commission discretion to provide exemption under specified conditions.[4] In addition to the 5 megawatt limitation which the statute provides for the proposed installed capacity of any exemptible project, a project, to be exemptible, must utilize either the water power potential of an existing dam or that of a so-called "natural water feature," without the need for a dam or man-made impoundment. The statute provides little guidance about what is meant by a "natural water feature". Nor does the legislative history indicate the possible configurations of project works that could be considered exemptible under this statutory concept. In the Commission's view, a natural water feature could be an elevated natural lake or a waterway, the topographical features of which permit diversion of some waters for purposes of power generation.

All projects which meet the threshold criteria of section 408 of the ESA are eligible for exemption under the Order No. 106 procedures.[5] However, when those procedures were developed, the term "natural water feature" was not

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[2] "Exemption from All of Part I of the Federal Power Act of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less" (Docket No. RM80-65), issued November 7, 1981, 45 Fed. Reg. 76115, November 18, 1980. The case-specific procedures (18 C.F.R. §§ 4.101–4.108) are initiated by a qualified exemption applicant who files an application for exemption of a specific proposed project. The Commission then issues a notice of the application. The qualifications of the project for exemption, consistent with various environmental requirements and the public interest, are determined by the Commission in conjunction with review by Federal and state fish and wildlife agencies, Federal land management agencies, and other interested persons.

[3] The ESA amends section 408 of PURPA, as follows:

(c) Section 408 of such Act (as amended by subsection (a) of this section) is further amended—

(1) by inserting "(a)" before "For purposes of this title"; and "(B) *The requirement in subsection (a)(1) that a project be located at the site of an existing dam in order to qualify as a small hydroelectric power project,* and the other provisions of this title which require that a project be at or in connection with an existing dam (or utilize the potential of such dam) in order to be assisted under or included within such provisions, *shall not be construed to exclude*—

"(1) from the definition contained in such subsection (a)(1), or

"(2) from any other provision of this title, *any project which utilizes or proposes to utilize natural water features for the generation of electricity, without the need for any dam or impoundment, in a manner which (as determined by the Commission) will achieve the purposes of this title and will do so without any adverse effect upon such natural water features.". (Emphasis Added)*

[4] Certain environmental requirements which apply to projects which the Commission licenses will also apply to projects which it exempts from licensing, including the National Environmental Policy Act of 1969 and the consultation provisions in section 30 of the Federal Power Act.

[5] Order No. 106 contains a waiver provision (§ 4.103(d)) designed to address the additional limitations which the Commission places on case-specific exemptions (*e.g.*, a 5 MW or less project within an existing licensed project may not ordinarily be exempted).

defined. This was because, at that time, the Commission had little information or experience as to the scope of this satutory term. Instead, the Commission used a broad definition of "dam" in § 4.102 of the exemption rules. This definition was designed to include among those exemptible projects that rely on existing dams for power generation any project that might utilize diversion or intake structures which could substantially obstruct a natural body of water, though in a manner different than a conventional impoundment-creating structure. This approach was developed pending further Commission consideration of the nature and scope of the so-called natural water feature project, as distinguished from a project which utilizes an existing dam (*i.e.*, a dam built on or before April 20, 1977 which will not require major alteration for power development).

It may be inferred from the statutory scheme and certain practical considerations that the "natural water feature" concept of section 408 of the ESA pertains to any project that uses naturally available hydraulic pressure. Such projects may have various configurations of project works. If a project were built to take advantage of the power potential of an elevated natural impoundment (a lake), the project's works would probably not include a dam but, instead, an intake structure and a penstock that convey water to the powerplant.[6] If a project were constructed to utilize a stream with a steep or precipitous gradient, including a waterfall, the project's works would in this case use a structure to divert water into a penstock to develop the naturally available hydraulic head differential between the diversion point and the location of the powerplant. Without construction of a diversion structure to direct water into a penstock, it would not be possible to take advantage of most natural water features for power generation.

B. The proposed rule

Section 408(c)(2) of the ESA specifically states that the Commission may determine how best to exempt natural water feature projects in order to achieve the purposes of Title IV of that Act. In the absence of express legislative guidance, the Commission proposes to revise in part the definition of "small hydroelectric power project" (§ 4.102(d)) to indicate the parameters of what the Commission will consider to be a natural water feature project not requiring an existing dam. Any diversion or intake structure utilized by such a project is limited to not more than six feet in height. Such structure may not create a pool larger than one acre-foot in volume.[7] In addition, the definition of "dam" (§ 4.102(a)) would be amended to exclude diversion structures which do not impound water so as to create artificially the hydraulic head used for power generation. Because a diversion structure will not be a dam within the meaning of the proposed rule, it need not be "existing" on or before April 20, 1977, in order to qualify a project for exemption.

The Commission's experience in licensing hydroelectric projects with a capacity of 5 MW or less and the record on case-specific exemptions under Order No. 106 demonstrate that by far the most feasible kind of natural water feature project is the project which removes by means of a diversion structure some water from a stream with a steep gradient. The diversion structure may be a log, rock piles, a submerged intake box, or a wood or concrete structure that spans all or part of the

[6] *See* diagrams attached to the mimeograph version of this notice available at the Commission's Division of Public Information during regular business hours. The diagrams are also filed as a part of the original document.

[7] The height limitation for diversion or intake structures and for pondage are based on the distinction drawn by the Congress for the National Program of Inspection of Dams, Act of August 8, 1972, 44 U.S.C. 467 *et seq.* However, the pondage limitation in the rule is one acre-foot, as opposed to 15 acre-feet in the statute.

stream. All of these works serve the same basic function, that is, to remove some portion of the water from the streambed for delivery to a powerplant. Such structures are not designed to impound water for daily, weekly, monthly, or seasonal flow regulation, storage, or peaking operations.

Were the Commission to treat all diversion structures as dams and therefore require that, to be exemptible, such structures must have existed on or before April 20, 1977, very few, if any, natural water feature projects would be exemptible under section 408 of the ESA. Several factors indicate this. The technical and economic attractiveness of small diversion-type projects is a relatively recent phenomenon and few diversion structures otherwise qualified to be natural water feature projects were built before April 20, 1977. In addition, most exemptible natural water feature projects which utilize diversion structures would be located in the West and will frequently take advantage of seasonal heavy flows, thus standing idle for much of the year. Order No. 106 (*see* § 4.102(l) and (m)) requires that new or additional capacity be installed in order to qualify for exemption, but maximum feasible capacity is usually installed at these projects when they are developed; adding an increment of capacity to an existing project is therefore not economically feasible for such projects. This means that only new diversion projects will generally be exemptible. Moreover, the opportunities to utilize an elevated lake to develop the new or additional capacity required for exemptions are extremely limited.

The Commission believes that Congress did not intend that the authority provided the Commission to exempt natural water feature projects should be so narrowly applied as to become insignificant. A statute should be construed so that no clause, sentence, or word becomes superfluous, void, or insignificant.[8] Congress' specific reference to the exemptibility of any project which utilizes a natural water feature could become insignificant or superfluous, if diversion facilities were considered not to be natural water feature projects. In addition, unnecessarily narrow or strict interpretations of a statute granting administrative powers should not be allowed to defeat its obvious purpose.[9]

A major purpose of Title IV of the ESA is "to provide further encouragement for the development of small hydroelectric power projects." [10] The approach proposed in this rulemaking would enable a greater number of projects with entirely new capacity to qualify for exemption and would thereby promote this statutory objective. A more restrictive approach would compel the developers of most such projects to seek a license and could frustrate the very statutory purpose for permitting the Commission to exempt natural water feature projects from provisions of the Act.

The rule also proposes to revise the definition of "dam", as it applies to exemptions, to distinguish diversion structures from other kinds of project works. The term "impoundment," when used in conjunction with "dam," connotes a project designed to obstruct the stream flow and, by backing up large quantities of water, create hydraulic pressure (head) behind the impoundment structure. As proposed, the revised definition of "small hydroelectric power project" is intended to convey the idea that diversion facilities do not restrain the quantity of stream flow necessary to create head.

The power potential naturally present at such sites is made available for power generation merely by delivering the water in a manner which takes full advantage of *natural* topographical features. The minimum pondage necessary to force water into a penstock and create favorable hydraulic conditions, such as preventing air from entering the penstock, is not an

[8] *See* generally, 2A (Sutherland) Statutes and Statutory Construction, (4th ed. 1973) at § 46.06.

[9] 3 Sutherland, at § 65.03.

[10] Section 402 of the ESA, 29 U.S.C. 7372.

impoundment as that term is normally understood.

C. Case-Specific Versus Categorical Exemption

At the time the Commission conducted hearings on the proposed categorical exemption rule in Docket No. RM81-7,[11] it received oral and written comment on the nature and location of natural water feature projects and whether such project could be defined in sufficiently precise terms for a categorical exemption. The Commission examined the plausibility of exempting all such projects by operation of a generic rule which would provide generic terms and conditions of exemption. It determined that categorical exemption of natural water feature projects is not feasible for various reasons.

First, the configuration and probable location of the project works which would be constructed to utilize a natural water feature are difficult to ascertain generically. This is partly because there are a variety of topographical circumstances where such projects could be developed. Second, the environmental concerns that would attend generic exemption procedures for such developments would be difficult to assess, thereby leading to generic terms and conditions that might be to extensive or otherwise inappropriate for any particular exemptible project. These problems suggest that case-specific exemption is both the most practical and efficient approach to the exemption of natural water feature projects.

The propriety of case-specific, as opposed to categorical, exemption for natural water feature projects is reinforced by the words of the statute which states that an exemption must be "without any adverse environmental effect upon such natural water feature". The case-specific procedures permit the Commission and the relevant state and Federal fish and wildlife agencies to ascertain whether the affected water feature would suffer adverse impacts which could not be mitigated by the design features of the proposed project works, adjustments to the operation of the proposed project, or by means of the terms and conditions of exemption. For example, sufficient stream flows or minimum diversions could be prescribed for particular projects under case-specific review to ensure continued protection of water quality and downstream fish and plant populations. Since review by appropriate environmental agencies will occur for each exemptible projects under the case-specific procedures, the Commission believes that the exemption rule will not result in adverse impacts on natural water features.

With respect to environmental impacts, an examination of the physical relationships between the dam height, impoundment volume, and typical minimum flow restrictions shows the maximum stream segment affected, as well as the area more typically affected. For a stream which has a width of 50 feet, the maximum affected length of river segment covered by "pondage" behind a diversion structure would be 600 feet. This maximum impact would be associated with diverting flows on a stream with a gradient of 50 ft./mile, usually a highly uneconomical proposition. A more typical range of impacted stream lengths and impoundment volumes for the type of stream gradients of interest are as follows:

Stream width (feet)	Pondage volume (acre-feet)	Gradient (foot/mile)	Length affected (feet)
25	.25	100	[1] 310
50	.50	100	310
25	.03	2000	[2] 15
50	.06	2000	15

[1] Maximum case.
[2] Minimum case.

[11] Notice of Proposed Rulemaking, "Exemption from Licensing Requirements of Part I of the Federal Power Act of Certain Categories of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less," issued December 22, 1980, 46 *Fed. Reg.* 1291, January 6, 1981. The Commission issued a Final Rule in this docket on October —, 1981, designated as Order No.?

In addition, state agencies with responsibilities for managing fish and wildlife may prescribe, during case-specific consultations, minimum flow requirements at the diversion structure sufficient to protect the aquatic habitat in the stream between the points in the stream where water is diverted and where it is subsequently reintroduced after power production. The rate of flow downstream of the powerplant would be the same as would occur naturally. Examples of a minimum flow prescribed by an agency for the stream segment between the diversion and discharge points might be the continuous natural minimum flow of the stream or the flow equaled or exceeded at the site 85 or 90 percent of the time.

II. Other Revisions

A. Change in § 4.33(a)

The Commission proposes to amend § 4.33(a)(2) of its regulations, consistent with changes made in a recent order.[12] The amendment would preclude the filing of notices of intent to file a preliminary permit application for natural water feature projects but would also provide 30 days more for filing competing permit applications than notices of initial permit applications customarily provide for the filing of protests, interventions and competing applications. This provision is currently applied to projects located at existing dams. The so-called natural water feature projects, physically limited by the terms of § 4.102(1)(2), generally have the same conceptual simplicity as existing dam projects that makes it feasible to restrict somewhat the time available to competitors to prepare and file competing applications.

The proposed rule would also prevent one applicant from filing more than one notice of intent in a single proceeding.

B. Change in § 4.104

Section 4.104 of the Commission's regulations establishes definite relationships among exemptions, permits, licenses, and applications for any of these authorizations, if the subject of several applications and a Commission action pursuant to an application is the same hydroelectric power site or a mutually exclusive site. Paragraph (a)(2)(i) of § 4.104 addresses the appropriate timing of a competing exemption application when a preliminary permit application (and perhaps additional competing permit applications) have been filed. If there is more than one preliminary permit filed for a single site, it is unclear which public notice period (provided for each permit application) is the appropriate window for filing a competing exemption application. In other words, submittal of a second and competing permit application could, under § 4.104(a)(2)(i), afford a project owner sixty more days, in addition to the notice period on the initial permit application, to file an exemption application. This was not the Commission's intent. Competing applications for exemption or notices of intent to file such applications must be filed during the notice period for the initial permit application.

Section § 4.104(a)(2)(i) is amended to indicate that an application for exemption which competes with a first-filed preliminary permit application must be filed within the notice period for the "initial" permit application, without regard to any subsequently filed competing permit applications for which additional notice periods are provided.

III. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) requires certain analysis of proposed agency rules that will have a "significant economic impact on a substantial number of small entities."

Pursuant to section 605(a) of the RFA, the Commission hereby finds that the analysis requirements set forth in the statute do not apply to this rulemaking.

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[12] Order No. 183, "Revisions to Regulations Governing Applications for Preliminary Permits and License for Water Power Projects" (Docket No. RM81-15), issued October 29, 1981.

The primary purpose of this proposal is to clarify exemption procedures already established for small hydroelectric power projects and to expand, to some extent, the kinds of projects which could be exempted under the rubric of "natural water feature projects." However, the Commission cannot estimate which entities will apply for exemption for natural water feature projects and therefore what the impact on small entities will be. Although the proposed exemption rule may assist small private developers or municipalities to obtain exemption, it will not assist this group any more or any less than others. Accordingly, on balance, there seems to be no significant impact.

If, in a final rule, the Commission were to provide for exemption of diversion-type projects, as this rule proposes, small entities which would otherwise be required to obtain a license for certain small hydroelectric power projects could resort to exemption. Moreover, by limiting the use of notices of intent for such projects, the Commission wishes to avoid delays occasioned by the filing of notices of intent to submit competing preliminary permit applications for certain projects, in those instances. Concededly, this latter proposal will require would-be project sponsors (including small private developers and small municipalities) to reach a decision quickly about filing a competing application; this may create some minimal additional burdens for small private and public developers, but these slight burdens should be more than offset by the advantages small developers will realize by virtue of a shorter, less costly application process and more rapid Commission decision making. Accordingly, any net economic impact of this change would benefit any small private or municipal developer.

In view of the minimal effects of the proposed changes in the Order No. 106 definitions and the restriction on notices of intent, the Commission believes that certification of no significant economic impact is appropriate.

IV. Comment Procedure

The Commission invites interested persons to submit written comments on the matters proposed in this notice. An original and 14 copies of such comments must be filed with the Commission not later than December 7, 1981. Comments submitted by mail should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should indicate the name, title, mailing address and telephone number of the person to whom communications concerning the proposal should be addressed. Comments should reference Docket No. RM82-2 on the outside of the envelope and on all documents therein. Written comments will be placed in the public files of the Commission and will be available for inspection at the Commission's Division of Public Information, Room 1000, address above, during regular business hours. The Commission will consider all comments submitted before final action.

(Energy Security Act of 1980, Pub. L. 96-264, 94 Stat. 611; Federal Power Act, as amended, 16 U.S.C. 792-828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601-2645; and the Department of Energy Organization Act, 42 U.S.C. 7101-7352; E. O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission proposes to amend Part 4 of the Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 4—LICENSES, PERMITS, EXEMPTIONS, AND DETERMINATION OF PROJECT COSTS

1. Section 4.33 is amended by revising paragraph (a)(2) to read:

§ 4.33 Filing and disposition of conflicting applications.

(a) * * *

(2) A notice of intent to file a competing application for preliminary permit may not be submitted for any

proposed major project—existing dam as defined in § 4.50(b)(5) of this chapter, any proposed minor water power project, as defined in § 4.60(b)(4) of this chapter, which utilizes an existing dam, or any water power project with an installed capacity of 5 megawatts or less which utilizes a natural water feature, as defined in § 4.102(1)(2). Any competing application for preliminary permit for a proposed major project—existing dam, minor water power project which utilizes an existing dam, or water power project 5MW or less which utilizes a natural water feature, must be submitted not later than 30 days after the last date for filing protests and petitions to intervene prescribed in the public notice issued under § 4.31(c)(2) of this chapter for the initial application. A competing applicant may file only one notice of intent for any project site during a license, permit, or exemption proceeding.

* * * * *

2. Section 4.102 is amended by revising paragraph (a) and paragraph (l)(2) to read as follows. The introductory text of paragraph (l) is shown for the convenience of the user.

Subpart K—Exemption of Small Hydroelectric Power Projects of 5 Megawatts or Less

* * * * *

§ 4.102 Definitions.

For purposes of this subpart—

(a) "Dam" means any structure for impounding water which is usable for electric power generation, if the impoundment supplies all, or the substantial part of, the total hydraulic pressure (head) developed for such generation.

* * * * *

(l) "Small hydroelectric power project" means any project in which capacity will be installed or increased after the date of application under this subpart and which will have a total installed capacity of not more than 5 megawatts and which:

* * * * *

(2) Would utilize for the generation of electricity a natural water feature, such as a natural lake, waterfall, or the gradient of a natural stream, without the need for a dam and man-made impoundment, and contains a diversion or intake structure which:

(i) Does not exceed six feet in height from the lowest point of the natural streambed at the downstream toe of the structure to the lowest point on the crest of the structure; and

(ii) Does not create pondage of more than one acre-foot (1233.5 cubic meters) of water.

3. Section 4.104 is amended by revising paragraph (a)(2)(i) to read:

§ 4.104 Relationships among applications, exemptions, permits, and licenses.

* * * * *

(a) *Limitations on submission and acceptance of exemption applications.*

* * * * *

(2) *Pending permit or license application.* (i) *Pending permit application.* If a preliminary permit application for a project has been accepted for filing, an application for exemption of that project from licensing or a notice of intent to submit such an application may be submitted not later than the last date for filing protests or petitions to intervene prescribed in the public notice issued for the initial permit application under § 4.31(c)(2) of this chapter.

* * * * *

¶ 32,173 High-Cost Gas Produced From Tight Formations; Wolfcamp Formation (Texas-14)

46 F. R. 55540 (November 10, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas-14)]

High-Cost Gas Producted From Tight Formations; Wolfcamp Formation

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that the Wolfcamp Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 4, 1981. *Public Hearing:* No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 19, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Issued: November 4, 1981.

I. Background

On September 21, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Wolfcamp Formation in the Gomez, N.W. (Wolfcamp) Field in the northern portion of Pecos County and in the Wolf (Wolfcamp) Field in the extreme southwest portion of Loving County, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Wolfcamp Formation in these two fields be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Gomez, N.W. (Wolfcamp) Field and the Wolf (Wolfcamp) Field where the Wolfcamp Formation is encountered be designated as a tight formation. The Gomez, N.W. (Wolfcamp) Field is located in northern Pecos County northwest of Fort Stockton, Texas, and contains approximately 24,457 acres. The Wolf (Wolfcamp) Field is located in the extreme southwestern portion of Loving County, between the town of Mentone, Texas, and the Pecos River in section 78, 79, 80, 81, 82 in Block 33, H&TC RR Company Survey. Both fields are part of Railroad Commission District 8.

The vertical interval requested for tight formation designation in the Gomez, N.W. (Wolfcamp) Field is that interval from 11,384 feet to 11,720 feet in the log of the Forest Oil Corporation No. 1 Garupa well. The zone has sands

which were deposited in the submarine fan complex and are poorly sorted containing low values of porosity and permeability.

The gross thickness requested in the Wolf (Wolfcamp) Field is from 10,118 feet to 10,696 feet as measured in the log of the Cobb No. 1 Wolf well. The producing zone is a low permeability reservoir of detrital nature deposited in the deep Delaware Basin under low energy conditions.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Wolfcamp Formation in the Gomez, N.W. (Wolfcamp) Field and the Wolf (Wolfcamp) Field as described and delineated in Texas' recommendation as filed with the Commission be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.W., Washington, D.C. 20426, on or before December 4, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—14), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 19, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703 is amended by adding new paragraph (d)(74) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the offical files of the jurisdictional agency that submitted the recommendation.

* * * * *

(56) through (73) [Reserved]

(74) *Wolfcamp Formation in Texas.* RM79–76 (Texas—14).

(i) *Gomez, N.W. (Wolfcamp) Field.*

(A) *Delineation of formation.* The Wolfcamp Formation in the Gomez, N.W., (Wolfcamp) Field is located in northern Pecos County, northwest of Fort Stockton, Texas, and contains approximately 24,457 acres.

(B) *Depths.* The top and base of the Wolfcamp Formation are found at the approximate depths of 11,384 feet and 11,720 feet, respectively as measured in the log of the Forest Oil Corporation No. 1 Garupa Well.

(ii) *Wolf (Wolfcamp) Field.*

(A) *Delineation of formation.* The Wolfcamp Formation in the Wolf (Wolfcamp) Field is located in extreme southwest Loving County between the town of Mentone, Texas, and the Pecos River in Sections 78, 79, 80, 81, 82, in Block 33, H&TC RR Company Survey.

(B) *Depths.* The top and base of the Wolfcamp Formation are found at the approximate depths of 10,118 feet and 10,696 feet, respectively, as measured in the log of the Cobb No. 1 Wolf Well.

¶ 32,174 High-Cost Gas Produced From Tight Formations (Nebraska-1)

46 F. R. 56428 (November 17, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Nebraska-1)]

High-Cost Gas Produced From Tight Formations; Proposed Designation

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Nebraska that the Niobrara Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 7, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 23, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

Issued: November 6, 1981.

SUPPLEMENTARY INFORMATION:

I. Background

On January 23, 1981, the State of Nebraska Oil and Gas Conservation Commission (Nebraska) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Niobrara Formation located in Chase, Cheyenne, Deuel, Dundy, Frontier, Garden, Hitchcock, Keith, and Perkins Counties, Nebraska, be designated as a tight formation. Nebraska submitted supplemental data in support of its recommendation to the Commission on July 17, 1981, and October 19, 1981. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Nebraska's recommendation that the Niobrara Formation be designated a tight formation should be adopted. Nebraska's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located in the southwest corner of Nebraska in the Denver-Julesburg Basin. It is situated in all of Chase, Deuel, Dundy, Hitchcock, Keith, and Perkins Counties, the western half of Frontier County, the eastern half of Cheyenne County, and the southernmost third of Garden County, Nebraska. The recommended area contains about 6,970 square miles, of which approximately 93.1 percent is fee acreage and 6.9 percent is state land. The average depth to the top of the producing interval is 2,450 feet. The Niobrara Formation measures about 400 feet in gross

thickness and underlies the Fort Hays Limestone Formation and overlies Pierre Shale Formation.

III. Discussion of Recommendation

Nebraska claims in its submission that evidence gathered from its public records demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Nebraska further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Nebraska that the Niobrara Formation, as described and delineated in Nebraska's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before December 7, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Nebraska-1), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 23, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342)

PART 271—CEILING PRICES

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, in the event Nebraska's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

Section 271.703 is amended by adding new paragraph (d)(79) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(56)-(78) [Reserved]

(79) *Niobrara Formation in Nebraska.* RM79–76 (Nebraska-1).

(i) *Delineation of formation.* The Niobrara Formation is found in all of Chase, Deuel, Dundy, Hitchcock, Keith, and Perkins Counties, the western half of Frontier County (Townships 5 through 8 North, Ranges 27 through 30 West), the eastern half of Cheyenne County (Townships 12 through 17 North, Ranges 46 through 49 West), and the southern most third of Garden County (Townships 15 through 19 North, Ranges 41 through 46 West).

(ii) *Depth.* The Niobrara Formation underlies the Fort Hays Limestone Formation and overlies the Pierre Shale Formation. The average depth to the top of the Niobrara Formation is 2,450 feet.

¶ 32,175 High-Cost Gas Produced From Tight Formations (Texas-7 Addition)

46 F. R. 56429 (November 17, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas-7 Addition)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that an additional area of the Lower Wilcox Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 7, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 23, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson (202) 357-8556.

Issued: November 6, 1981.

SUPPLEMENTARY INFORMATION:

I. Background

On August 25, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that an additional area of the Lower Wilcox Formation, located in the southeastern part of the State of Texas, be designated as a tight formation. The Commission previously adopted a recommendation that the Lower Wilcox Formation in parts of Wharton, Austin and Colorado counties be designated as a tight formation (Order No. 133, issued in Docket No. RM79-76 (Texas-7) on February 19, 1981). Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Lower Wilcox Formation in the Bonus, S. (Wilcox 13,900') Field be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Lower Wilcox Formation, encountered in the Bonus, S. (Wilcox 13,900') Field located in the northwestern portion of Wharton County, Texas, Railroad Commission District 3, be designated as a tight formation. The recommended area is approximately 10 miles south of the town of Eagle Lake, and is within a 2.5 mile radius around the Laurel Fuel Company Winterman No. 3 well, which

is located 2150 feet northwest of the southeast boundary and 2500 feet southwest of the northeast boundary of the Andrew Rabb Survey A–53 in Wharton County. (A more detailed description of the recommended area is contained in the recommendation on file with the Commission.) The Lower Wilcox Formation is located below the Claiborne Formation and above the Midway Formation. In the Laurel Fuel Company Winterman No. 3 well, the only producing well in the formation, the top of the recommended portion of the Lower Wilcox Formation is located at an approximate depth of 13,900 feet and is between 60 and 70 feet thick.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay sect.. of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Lower Wilcox Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before December 7, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Texas—7 Addition), and should give reasons including supporting data for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any persons wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 23, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Section 271.703 is amended by revising paragraph (d)(18) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(18) *Lower Wilcox Formation in Texas.* RM79–76 (Texas–7).

(i) *Three County Area.*—(A) *Delineation of formation.* The Lower Wilcox Formation is found in the southern portion of Austin County, the northern portion of Wharton County, and the eastern portion of Colorado County, Texas.

(B) *Depth.* The top of the Lower Wilcox is located at an approximate depth of 11,700 feet and the base is located at an approximate depth of 12,700 feet, giving a thickness of 1,000 feet.

(ii) *Bonus, S. (Wilcox 13,900') Field.*—(A) *Delineation of Formation.* The Lower Wilcox Formation is found in the Bonus, S. (Wilcox 13,900') Field, Wharton County, Texas, approximately 10 miles south of the town of Eagle Lake. The formation is described by a 2.5 mile radius around the Laurel Fuel Company Winterman No. 3 well and covers approximately 19.6 square miles.

(B) *Depth.* The top of the Lower Wilcox Formation is at an approximate depth of 13,900 feet and is between 60 and 70 feet thick.

¶ 32,176 High-Cost Gas Produced From Tight Formations (Louisiana-6)

46 F. R. 56819 (November 19, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Louisiana—6)]

High-Cost Gas Produced From Tight Formations; James Lime Formation, Louisiana

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the State of Louisiana Office of Conservation that the James Lime Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 14, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 30, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Issued November 13, 1981.

I. Background

On October 5, 1981, the State of Louisiana, Office of Conservation (Louisiana) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the James Lime Formation, in DeSoto Parish, northwestern Louisiana, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this notice of proposed rulemaking is hereby issued to determine whether Louisiana's recommendation that the James Lime Formation be designated a tight formation should be adopted. Louisiana's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Louisiana recommends that the James Lime Formation in the area of the Benson Field in the southern portion of DeSoto Parish, Louisiana be designated as a tight formation. The area recommended for designation, which covers 108 square miles, is as follows:

T10N–R13W	Sections 1–18
T10N–R14W	Sections 1–18
T11N–R13W	Sections 1–36
T11N–R14W	Sections 1–36

The top of the James Lime Formation is encountered at approximately −5072 feet subsea in the northwest portion of the recommended area and at approximately −5400 feet subsea in southern portion. It is situated directly below the Bexar Formation and above the Pine Island Formation. The maximum thickness of the formation is

approximately 260 feet. Louisiana states that there are 6 wells currently producing from the James Lime Formation.

III. Discussion of Recommendation

Louisiana claims in its submission that evidence gathered and presented at a public hearing in support of this recommendation demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Louisiana further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Louisiana that the James Lime Formation as described and delineated in Louisiana's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before December 14, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Louisiana—6), and should give reasons including supporting data for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 30, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3432))

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Louisiana's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703 is amended by adding new paragraph (d)(78) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(78) *James Lime Formation in Louisiana. RM79-76 (Louisiana—6).*—(i) *Delineation of formation.* The James Lime Formation is found in the area of the Benson Field in the southern portion of DeSoto Parish, Louisiana. The formation underlies the following areas:

Township 10 North, Range 13 West, Sections 1 through 18;
Township 10 North, Range 14 West, Sections 1 through 18;
Township 11 North, Range 13 West, all Sections;
Township 11 North, Range 14 West, all Sections.

(ii) *Depth.* The top of the James Lime Formation is at approximately −5072 feet subsea in the northwest and approximately −5400 feet subsea in the south. The maximum thickness of the formation is approximately 260 feet.

¶ 32,177 High-Cost Gas Produced From Tight Formations (Texas-3 Addition)

46 F. R. 56820 (November 19, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—3 Addition)]

High-Cost Gas Produced From Tight Formations; Cisco Sandstone Formation, Texas

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that an additional area of the Cisco Sandstone Formation located in the Sallie (Cisco) Field be designated as a tight formation under § 271.703(d)

DATE: Comments on the proposed rule are due on December 14, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 30, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Issued: November 13, 1981.

I. Background

On September 21, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Cisco Sandstone Formation located in the northeastern corner of Reagan County, and the southwest corner of Sterling County, in west Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that an additional area of the Cisco Sandstone Formation in the Sallie (Cisco) Field be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Cisco Sandstone Formation encountered in Sections 58, 59, 60, Block 2, T&P RR Survey, Reagan County, and Section 42, Block 2, T&P RR Survey, Sterling County, be designated as a tight formation. Reagan County and Sterling County are part of Railroad Commission Districts No. 7C and 8, respectively. The formation is an expansion of the area previously designated as a tight formation in Order No. 125 issued January 23, 1981, in Docket No. RM79-76 (Texas—3). The Cisco Sandstone is located below the Wichita Formation and above the Canyon Formation. Cisco Sand deposition occurred in the

Pennsylvania Period, in a shallow water environment, resulting in sands that are very shaley.

Currently, three wells are producing within the recommended area. The top of the Cisco Sandstone Formation appears at an approximate depth of 8,030 feet and is approximately 300 feet thick.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through infomation and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Cisco Sandstone Formation, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed ruelmaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before December 14, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. Rm79-76 (Texas—3 Addition), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 30, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by revising paragraph (d)(12) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed

description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

• • • • •

(12) *Cisco Sandstone Formation in Texas. RM79-76 (Texas-3)*—(i) *Sallie (Cisco) Field*—(A) *Delineation of Formation.* The Cisco Sandstone Formation is found in Section 72, Block 2, T&P RR Survey, northeast Reagan County, Texas.

(B) *Depth.* The top of the Cisco Sandstone Formation is located at an approximate depth of 8,260 feet with an approximate thickness of 28 feet.

(ii) *Sallie (Cisco) Field Addition*—(A) *Delineation of Formation.* The Cisco Sandstone Formation is located in Sections 58, 59, and 60, Block 2, T&P RR Survey, northeast Reagan County, Texas and Section 42, Block 2, T&P RR Survey, southwest Sterling County, Texas.

(B) *Depth.* The top of the Cisco Sandstone Formation appears at an approximate depth of 8,030 feet and is approximately 300 feet thick.

¶ 32,178 High-Cost Gas Produced From Tight Formations (Texas-11 Addition)

46 F. R. 56822 (November 19, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—11 Addition)]

High-Cost Gas Produced From Tight Formations; Wilcox Formation, Texas

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by Section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking contains the recommendation of the Railroad Commission of Texas that an additional area of the Wilcox Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on December 14, 1981.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on November 30, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

I. Background

On September 21, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that an additional area of the Wilcox Formation located in Starr County, Texas, be designated as a tight formation. The Commission currently has under consideration a recommendation that a portion of the Wilcox Formation in Webb County, Texas, be designated as a tight formation (Docket No. RM79-76, (Texas—11)). Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Wilcox Formation in the Roma, W. (Wilcox 10,100) Field be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Wilcox Formation in the area of the Roma, W. (Wilcox 10,100) Field in the western portion of Starr County, Texas, Railroad Commission District 4, be designated as a tight formation. The area recommended is within a 2.5 mile radius around the Border Exploration Company No. 1 H.P. Guerra, Jr., et al., well and is adjacent to the Rio Grande River. The top of the recommended formation appears at approximately 9,750 feet and extends to 10,750 feet giving a total thickness of 1,000 feet. The Border Exploration Company No. 1 H.P. Guerra, Jr., et al. well is the only completion in the recommended formation.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information

and testimony presented at a public hearing in support of this recommendation demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Wilcox Formation as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before December 14, 1981. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—11 Addition), and should give reasons including supporting data for any recommendation. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than November 30, 1981.

(Natural Gas Policy Act of 1978 (15 U.S.C. 3301-3432.))

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703 is amended by adding paragraph (d)(58) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's offical file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(58) *Wilcox Formation in Texas.* RM79-76 (Texas—11)—(i) *Aviators, N.*

(12,000) Field—(A) *Delineation of formation.* The Wilcox Formation found in the area of the Aviators, N. (12,000) Field, Webb County, Texas, is within a 2.5 mile radius around the Pennzoil Producing Company No. 53–1 B.M.T.—Alice B. Hall well and covers approximately 19.6 square miles.

(B) *Depth.* The top of the Wilcox Formation, Aviators, N. (12,000) Field, is at approximately—11,085 feet subsea and is 114 feet thick.

(ii) *Roma, W. (Wilcox 10,100) Field*—(A) *Delineation of formation.* The Wilcox Formation found in the area of the Roma, W. (Wilcox 10,100) Field, Starr County, Texas, is within a 2.5 mile radius around the Border Exploration Company No. 1 H.P. Guerra Jr., et al. well and is adjacent to the Rio Grande River.

(B) *Depth.* The top of the Wilcox Formation, Roma, W. (Wilcox 10,100) Field, is at approximately 9,750 feet and extends to 10,750 feet, resulting in a total thickness of 1,000 feet.

¶ 32,179 Form No. 423: Monthly Report of Cost and Quality of Fuels for Electric Plants

46 F. R. 60214 (December 9, 1981).

18 CFR Part 141

[Docket No. RM82-4]

Form No. 423: Monthly Report of Cost and Quality of Fuels for Electric Plants; Proposed Revision

Issued: December 3, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to revise its Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants" and its corresponding regulations at 18 CFR 141.61. As proposed, Form No. 423 would be amended so as to apply only to plants that have a stream electric generating capacity of 50 MW or greater. In addition, certain data requests in the form would be clarified, and the number of copies to be submitted with the original would be reduced. The proposed revision of Form 423 is part of the Commission's ongoing program to eliminate reporting requirements that are not necessary to the performance of the Commission's regulatory responsibilities and to reduce the burden associated with necessary filing requirements.

DATE: Comments are due by January 4, 1981.

ADDRESSES: Comments to this Notice should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 and should reference Docket No. RM82-4.

Copies of the proposed Form No. 423 are available at: Federal Energy Regulatory Commission, Division of Public Information, 825 North Capitol Street NE., Room 1000, Washington, D.C. 20426, (202) 357-8055.

FOR FURTHER INFORMATION CONTACT: Alexander Gakner, Office of Electric Power Regulation, 825 North Capitol Street NE., Room 507H-RB, Washington, D.C. 20426, (202) 376-9369.

SUPPLEMENTARY INFORMATION:

A. Background

The Federal Energy Regulatory Commission (Commission) proposes to amend Form No. 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants" and to amend its regulations prescribing that form (18 CFR 141.61).[1] This rulemaking has been initiated as part of the Commission's ongoing program to review the Commission's filing requirements and reduce unnecessary reporting burdens.

Form No. 423 solicits information about the cost, quantity, and quality of fuel received monthly at generating plants owned or operated by electric utilities that are subject to the jurisdiction of the Commission under the Federal Power Act.[2]

Form No. 423 provides the Commission with information about utility fuels; specifically, their cost, quality (energy content, sulfur content, ash content), geographic source, type of contract, and method of mining (coal). The information is used to evaluate fuel quality and costs in electric rate cases, and also to evaluate fuel purchase

[1] The proposed Form No. 423 (Appendix) is not being printed in the **Federal Register**. Copies of the proposed Form No. 423, including all instructions to the form, are available at the Commission's Division of Public Information, 825 North Capitol Street NE., Room 1000, Washington, D.C. 20426, (202) 357-8055.

[2] The Commission is authorized to regulate electric utilities engaged in interstate commerce under Part II of the Federal Power Act (16 U.S.C. 792-828c) pursuant to section 402 of the Department of Energy Organization Act (42 U.S.C. 7172(b)). The Commission collects information in the Form No. 423 under section 304 of the Federal Power Act pursuant to a delegation of authority from the Secretary of Energy to the Commission (Delegation Order No. 0204-1 (October 1, 1977)).

practices of electric utility companies according to section 208 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824d(f)).[3] The information is also used by other Federal agencies, such as the Environmental Protection Agency, the Departments of Labor and Commerce, the Federal Reserve Board, and the General Accounting Office, in the discharge of their various statutory responsibilities. Information in the form is collected every month from about 900 plants.

The Form No. 423 has been prescribed by Commission regulations since 1972.[4] After reevaluating the form, the Commission now proposes to increase the threshold capacity requirement that triggers the requirement to submit the form and the Commission proposes to alter the definition of that capacity requirement. The proposed amendments would also clarify certain data requests so as to prevent the filing of inconsistent data by reporting entities and to provide more meaningful information to the Commission. These amendments should result in a net decrease of approximately 17 percent in the number of utility plants that must gather the data, record it, and submit it to the Commission. Because fewer companies would be required to file the Form No. 423 and because the form itself would be simplified, the total number of hours spent annually in preparing the form should decrease correspondingly. Finally, the respondents would be required to file four copies of the completed form, rather than six.

B. Summary of Proposed Changes

The Commission proposes to revise the general instructions in Form No. 423 so that the filing requirement is triggered if an electric power producer's plant possesses a rated generating capacity of 50 megawatts (MW), rather than 25 MW as is now required. The minimum capacity requirement would be determined by reference to only steam-electric facilities. Combustion turbine and internal combustion engine plants, which are used to provide power during peak system load, would no longer be included in computing the filing threshold.

The Commission proposes these changes because the plants that have less than a 50 MW rated generating capacity, or that operate by combustion turbine or internal combustion, represent less than five percent of the generating capacity that is reported in the Form No. 423 and this type of information is not needed on a monthly basis. Information about these smaller plants can be obtained in individual rate proceedings or through specific data requests, as needed. However, the Commission believes that a threshold higher than 50 MW would not provide sufficient information to the Commission for the analysis of rate filings.

Specific instructions in the form would be amended in certain respects. For reporting purposes, a central storage facility would be treated as a plant, to clarify the classification of such facilities. The instructions would also require respondents to provide certain additional detail in the form to more clearly report their activities, such as indicating the expiration date (if such occurs within 24 months) of all contracts under which deliveries of coal or oil are made; and the name of the broker, if applicable, from whom coal was purchased during the reporting month. Finally, the instructions would be revised to include "flame stabilization" fuels in the instruction requiring fuel identification and to define "spot" purchase to be "shipments under purchase orders or contracts of less than one year duration".

[3] Section 208 requires the Commission to periodically review fuel purchaser practices and policies under automatic adjustment clauses in order to promote the efficient use of fuel and energy resources, and to evaluate the justness and reasonableness of rates charged by electric utilities.

[4] Docket No. R-432, Order No. 453, issued June 7, 1972 (37 FR 11860, June 15, 1972); revised July 19, 1974, Docket No. R-432-A, Order No. 512 (39 FR 34030, September 23, 1974).

The regulations at § 141.61 which prescribe the filing of Form No. 423 would be revised to reflect the increase in the minimum capacity requirement from 25 MW of steam-electric generating plant capacity to 50 MW rated steam-electric generating capacity. The regulations would also be revised to make certain non-substantive changes that more clearly describe who must file the form and when the filing is required.

C. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601–612) requires certain statements, descriptions, and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities".

Pursuant to section 605(b) of the RFA, the Commission certifies that this rule, if promulgated, will not have a significant economic impact on a substantial numer of small entities. Virtually all electric utility companies required to file the monthly report are large entities. Moreover, this rule, if promulgated, will reduce the filing burden on the electric utility companies because the proposed revisions will simplify the current report.

D. Written Comment Procedure

The Commission invites interested persons to submit written data, views and other information concerniing the matters set out in this Notice. An original and 14 copies of such comments should be filed with the Commission by January 4, 1981. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM82–4.

All written submissions to this rulemaking will be placed in the Commission's public files and will be available for public inspection at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, DC 20426, during regular business hours.

(Department of Energy Organization Act (42 U.S.C. 7101–7352); E.O. 12009, 3 CFR Part 142; Federal Power Act (16 U.S.C. 792–828c); Public Utility Regulatory Policies Act (16 U.S.C. 2601–2645))

In consideration of the foregoing, the Commission proposes to amend Form No. 423 as set forth in the Appendix, and Part 141 of Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 141—STATEMENT AND REPORTS (SCHEDULES)

Section 141.61 is revised to read as follows:

§ 141.61 FERC Form No. 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

(a) *Prescription.* The form of Monthly Report of Cost and Quality of Fuels for Electric Plants, designated herein as FERC Form No. 423, is prescribed for the month of January, 1982, and for each month thereafter.

(b) *Filing Requirements.* (1) *Who must file.* Each electric power producer with a rated steam-electric generating capacity of 50 megawatts or greater during the reporting month shall prepare and file with the Commission an original and conformed copies of FERC Form No. 423 pursuant to the General Instructions set out in that form.

(2) *When to file.* The completed report shall be filed on or before the 45th day after the end of the reporting month.

¶ 32,180 Tax Normalization for Certain Items Reflecting Timing Difference in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes

46 F. R. 60466 (December 10, 1981).

18 CFR Part 2

[Docket No. RM 80-42]

Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes; Opportunity for Submitting Additional Comments

Issued: November 30, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice Providing Time for Additional Comments.

SUMMARY: On May 6, 1981, 46 FR 26613, published May 14, 1981, the Commission issued a final rule (Order No. 144) in Docket No. RM-42 to require public utilities making rate filings under the Federal Power Act or interstate pipelines making rate filings under the Natural Gas Act to use tax normalization for certain timing differences to compute the income tax component of their costs of service. Petitions to rehear that final rule were received by the Commission and on July 2, 1981, pending a final order on rehearing in response to those petitions, the Commission stayed the effective date of the final rule.[1] Subsequent to these actions, on August 13, 1981, the Economic Recovery Tax Act of 1981 became law. A petition has been received by the Commission to reopen the rulemaking in light of this new tax law. Without deciding the merits of that petition, the Commission is providing a short time period for the receipt of additional comments to the rulemaking, those comments to be limited to the question of whether the new tax law requires amendment of the final rule.

IMPORTANT DATES: Comments should be received by December 21, 1981.

ADDRESS: All comments should cite to Docket No. RM80-42 and should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: John Conway, Acting Deputy Assistant General Counsel, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, Room 8106 (202) 357-8150.

SUPPLEMENTARY INFORMATION:

On May 6, 1981, the Federal Energy Regulatory Commission (Commission) issued a final rule in Docket No. RM80-42 which amended Part 2 of its regulations to require public utilities making rate filings under the Federal Power Act or interstate pipelines making rate filings under the Natural Gas Act to use tax normalization for miscellaneous timing differences to compute the income tax component of costs of service.[2] That rule was stayed on July 2, 1961, pending final Commission action on applications to rehear the rule.[3]

Subsequent to the issuance of both the final tax normalization rule and the Commission's order staying that rule, the Congress passed the Economic Recovery Tax Act of 1981.[4] On October 5, 1981, some participants in the rulemaking (the East Tennessee Group)

[1] Editorial Note: Not published in the **Federal Register**. See Docket Nos. RM 80-42, R-424, and R-446.

[2] Order No. 144, 46 FR 26613 (May 14, 1981).

[3] Docket Nos. RM80-42, R-424 and R-446, "Order Granting Rehearing for Purposes of Further Consideration and Providing for Stay" (issued July 2, 1981).

[4] Pub. L. No. 97-34 (August 13, 1981).

requested that the Commission institute extensive proceedings for re-examination of all aspects of its final rule in light of the new law.[5] This request has been opposed by other participants in the rulemaking.[6] The Commission expresses no opinion at this time on the merits of the petition of the East Tennessee Group.

However, the request of the East Tennessee Group raises the issue of the impact of the Economic Recovery Tax Act of 1981 on the final rule issued May 6, 1981. Because of the importance of this question and the fact that an answer to it may result in amendments to the final rule, the Commission is providing an opportunity for submission of additional comments in this rulemaking proceeding. These comments are limited to the narrow question of whether the new tax law requires amendment of the final rule. Because of the importance in completing this proceeding expeditiously and the narrow scope of the question to be commented upon, the time for submitting the additional comments is short.

Those wishing to submit comments on this issue should file their comments with the Commission by December 21, 1981. An original and fourteen conformed copies should be submitted to the Federal Energy Regulatory Commission, Office of the Secretary, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80-42. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Division of Public Information, 825 North Capitol Street, N.E., Washington, D.C. during regular business hours.

In order that all interested participants in this proceeding may be promptly notified of this opportunity to submit additional comments, the Secretary shall immediately serve all persons named on the service list established for this proceeding with a copy of this notice.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

[5] "Petition of East Tennessee Group, et al. for Reopening of Record of Order No. 144 to Reflect the Impact of the Economic Recovery Tax Act of 1981 and for Reconstruction," Docket Nos. Rm80-42, R-424, and R-446 (filed October 5, 1981).

[6] "Response to Petition of East Tennessee Group to Reopen the Record", Docket Nos. RM80-42, R-424, and R-446, filed on behalf of various utilities (filed October 20, 1981); "Opposition of Edison Electric Institute to Petition to Reopen", Docket No. RM80-42 (filed October 26, 1981).

¶ 32,181 High-Cost Gas Produced From Tight Formations (Texas-16)

46 F. R. 60467 (December 10, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—16)]

High-Cost Gas Produced From Tight Formations; Texas

Issued: December 7, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that the Olmos Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on January 6, 1982.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 22, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter W. Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

I. Background

On November 2, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Olmos Formation located in the northwest part of Webb County and the southern part of Dimmit County, Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas recommendation that the Olmos Formation in these two counties be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Olmos Formation in specifically designated areas of Webb and Dimmit Counties, Texas, Railroad Commission Districts 4 and 1, respectively, be designated as a tight formation. The geographical area covered by Texas' recommendation is all of that portion of Dimmit County, extending approximately 14 miles north of the northern boundary of Webb County, and all of that portion of northwest Webb County west of a north-south line extending south from a point approximately 1.5 miles east of the southwest corner of La Salle County and north of an east-west line located approximately 22 miles south of the southwest corner of La Salle County.

The vertical interval requested for tight formation designation is correlation to that interval from 4146 feet to 5237 feet as measured in the log of the Trans Delta Corporation Petty well No. 6-7. This well is located in Section 7, Block 8, of the I. & G.N.R.R. Co. Survey in the S.W. Catarina Field, Webb County, Texas. The Olmos Formation consists of a series of

alternating sands and shales of deltaic origin deposited along a late cretaceous shoreline.

III. Discussion of Recommenation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Olmos Formation in Webb and Dimmit Counties, as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before January 6, 1982. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—16), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 22, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301—3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703 is amended by adding new paragraph (d)(80) to read as follows:

271.703. Tight formations.

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the

designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(60) through (79) [Reserved]

(80) *Olmos Formation in Texas.* RM79-76 (Texas—16)

(i) *Delineation of formation.* The Olmos Formation is located in the northwest portion of Webb County and the southern portion of Dimmit County in Texas. The formation includes all of that portion of Dimmit County extending approximately 14 miles north of the northern boundary of Webb County, and all of that portion of northwest Webb County west of a north-south line extending south from a point approximately 1.5 miles east of the southwest corner of La Salle County and north of an east-west line located approximately 22 miles south of the southwest corner of La Salle County.

(ii) *Depths.* The top and base of the Olmos Formation are found at approximately depths of 4146 feet and 5237 feet, respectively, on the log of the Trans Delta Corporation Petty well No. 6-7. This well is located in Section 7, Block 8, of the I. & G.N.R.R. Co. Survey in the S.W. Catarina Field, Webb County, Texas.

¶ 32,182 High-Cost Gas Produced From Tight Formations (Texas-17)

46 F. R. 60468 (December 10, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—17)]

High-Cost Gas Produced from Tight Formations; Texas

Issued: December 7, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that the Massive "A" Sand Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on January 6, 1982.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 22, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, N. E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8317, or Walter W. Lawson, (202) 357–8556.

SUPPLEMENTARY INFORMATION:

I. Background

On November 3, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Massive "A" Sand Formation in the Chapa, East Field, Live Oak County, Texas, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that the Massive "A" Sand Formation in this field be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas recommends that the Chapa, East Field where the Massive "A" Sand Formation is encountered be designated as a tight formation. The Chapa, East Field is located in Live Oak County, Texas, Railroad Commission District 2.

The recommended area is within a 2.5 mile radius of the Aminoil USA, Inc., El Paso Natural Gas No. 5 well, the only well producing from the formation in the recommended area. This well is located in Section 299, Hooper & Wade A–250 Survey, which is situated in the southwest part of the county approximately 4 miles east of the McMullen County line. The average depth to the top of the formation is aproximately 11,600 feet and thickness varies from 220 feet in the northwest part to 560 feet in the southeast part of the recommended area.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80-68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Massive "A" Sand Formation in the Chapa, East Field as described and delineated in Texas' recommendation as filed with the Commission be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before January 6, 1982. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79-76 (Texas—17), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 22, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432.)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (81) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79-76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(60) through (80) [Reserved]

(81) *Massive "A" Sand Formation in Texas.* RM79-76 (Texas—17).

(i) *Delineation of formation.* The Massive "A" Sand Formation is found in the Chapa, East Field in southwestern Live Oak County, Texas, Railroad Commission District 2. The formation is described by a 2.5 mile radius around the Aminoil USA, Inc., El Paso Natural Gas No. 5 well located in Section 299, Hooper & Wade A–250 Survey, approximately 4 miles east of the McMullen County line.

(ii) *Depth.* The average depth to the top of the Massive "A" Sand Formation is approximately 11,600 feet and thickness varies from 220 feet in the northwest to 560 feet in the southeast.

¶ 32,183 Annual Report of Carriers by Pipeline: Form P

46 F. R. 60617 (December 11, 1981).

18 CFR Part 357

[Docket No. RM82-5]

Proposed Rulemaking To Amend Annual Report Of Carriers By Pipeline: Form P

Issued: December 4, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission is proposing to revise Form P, which is an annual report filed by oil pipeline companies in accordance with § 357.2 of the Commission's regulations (18 CFR 357.2). The proposed revisions will include deleting certain schedules and data columns in the Form P, adding new data elements, and consolidating and clarifying other information in the form. The Commission proposes to designate this revised annual report as "FERC Form No. 6 Annual Report of Oil Pipeline Companies". The proposed revisions are made as part of the Commission's ongoing program to review all of its reporting requirements and to eliminate those requirements that are not necessary to the performance of the Commission's responsibilities.

DATES: Written comments are due February 2, 1982.

ADDRESSES: Comments to this Notice should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and should reference Docket No. RM82-5.

Copies of the proposed Form No. 6 are available at: Federal Energy Regulatory Commission, Division of Public Information, 825 North Capitol Street, NE., Room 1000, Washington, D.C. 20426 (202) 357-8055.

FOR FURTHER INFORMATION CONTACT: Elaine Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3405N, Washington, DC 20426 (202) 357-9190.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is proposing to amend the annual report, Form P, which oil pipeline companies file in accordance with § 357.2 of the Commission's regulations (18 CFR 357.2). The Commission proposes to replace Form P with "FERC Form No. 6, Annual Report of Oil Pipeline Companies".[1] The proposed Form No. 6 is modeled after Form P but deletes certain schedules that collect information not pertinent to the Commission's regulation of these companies and includes other information requirements. This proposal is part of the Commission's ongoing program to review its reporting requirements and reduce unnecessary burdens by eliminating the collection of data that are not necessary to the performance of the Commission's regulatory responsibilities.

A. Background

Authority to regulate oil pipline companies was transferred from the Interstate Commerce Commission (ICC) to this Commission by section 402(b) of the Department of Energy Organization Act (DOE Act). (42 U.S.C. 717(b))[2]

The authority in section 402(b) to regulate the rates and charges of oil pipeline companies is provided in section 1 of the Interstate Commerce Act (ICA) (49 U.S.C. 1). The ability of the Commission to regulate rates effectively

[1] The proposed Form No. 6 (Appendix C) is not being printed in the **Federal Register**. Copies of the proposed form are available at the Commission's Division of Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8055.

[2] Section 402(b) provides that: [t]here are hereby transferred to, and vested in, the Commission all functions and authority of the Interstate Commerce Commission or any officer of component of such Commission where the regulatory function establishes rates and charges for the transportation of oil by pipeline or establishes the valuation of any such pipeline.

depends on its authority to collect pertinent information from the regulated companies. The Commission, therefore, exercises the authority under Section 20 of the ICA to require pipeline companies to file annual reports that include that information.[3]

Annual Report Form P was developed by the ICC to collect information that would enable it to carry out its rate regulation responsibility under the ICA. The form had been specifically required in § 1241.61 of the ICC's regulations (49 CFR 1241.61).[4] The Commission believes that many of the schedules in the report have been modeled after schedules in annual reports that were filed by other comon carriers regulated by the ICC. Such carriers were subject to a broader regulatory scheme than oil pipeline companies. Therefore, some of the information collected on Form P is unnecessary for the rate regulation of pipeline companies. For example, Schedule 205, "Compensating Balances and Short-Term Borrowing Arrangements," and Schedule 206, "Special Deposits," were included in Form P to collect information relating to Security and Exchange Commission disclosure requirements.

The Commission has also determined that some of the information collected by Form P need not be collected in the detail required by that report. For example, Schedule 210, "Notes Receivable," collects detailed information which could be obtained by the Commission from a specific company if the Commission determines at a later date that the information is necessary for rate regulation. A total figure for notes receivable is collected, however, on Schedule 200, "Comparative Balance Sheet Statement," which is not proposed to be revised in this rulemaking.

The Commission believes that reporting the type of information described under Form P constitutes a filing burden on the oil pipeline companies that can be reduced without impairing the Commission's ability to effectively regulate the rates and charges of these companies. As a result of the changes proposed in this form, the respondent burden should be reduced by about 20 percent.

The following are the proposals to revise Form P and to amend 18 CFR 357.2.

B. Proposed Revisions

The Commission proposes to revise Form P by redesignating that form as "FERC Form No. 6, Annual Report of Oil Pipeline Companies", by eliminating serveral schedules entirely, by eliminating columns from certain other schedules; and by redesigning the form and consolidating and clarifying the instructions. A new schedule would also be included to require certain additional information. The proposed revisions to the Form P are summarized on a chart in Appendix A attached to this notice.

The most significant deletions from the Form P are the deletions of the following schedules in their entirety:

Title of schedule and reference to schedule No. in Form P
Guaranties and suretyships, 110
Compensating balances and short-term borrowing arrangements, 205
Special deposits, 206
Notes receivable, 210
Accounts receivable, 212
Companies controlled through nonreporting intermediaries, 223
Sinking and other funds, 225
Rental expense of lessee, 243
Minimum Rental commitments, 244
Lessee disclosure, 245
Lease commitments—Present value, 246
Income impact—Leasee, 247

[3] Section 20 of the ICA authorizes the Commission to require reports from "carriers, lessors, and associations" and require answers to "questions upon which the Commission may deem information to be necessary * * *." This authority was transferred to the Commission in support of its responsibilities under section 402(b) of the DOE Act.

[4] By Order No. 119, (Docket No. PM81-8, issued December 19, 1980 46 FR 9043, January 28, 1981), the Commission transferred to Title 18 of the Code of Federal Regulations those regulations in Title 49 applicable to the Commission's oil pipeline jurisdiction. As part of this transfer, 49 CFR 1241.61 became 18 CFR 357.2.

Notes payable, 250
Accounts payable, 252
Long-term debt changes during the year, 261
Security for long-term debt, 262
Stock liabilities for conversion of securities of other companies, 272
Abstracts of terms and conditions of leases, 342
Rentals, 420
Abstracts of leasehold contracts, 422
Compensation of officers, directors, etc., 562
Competitive bidding—Clayton Antitrust Act, 595 [1]

The new schedule to be added would be entitled, "Statement of Changes in Financial Position" (a copy of which is attached to this proposal as Appendix B). It would require additional information on the finanical condition of pipelines that would be reported in place of other deleted data.

The Commission proposes to amend § 357.2 of the Commission's regulations by redesignating "Form P' as "FERC Form No. 6, Annual Report of Oil Pipeline Companies". The format regulations would also be revised to describe more clearly the requirements for filing the form. The changes, however would not change the substance of the current regulations.

C. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601–612) requires certain statements, descriptions, and analyses of proposed rules that will have a "significant economic impact on a substantial number of small entities".

Pursuant to section 605(b) of the RFA, the Commission certifies that this rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. Virtually all oil pipeline companies required to file the annual report are large entities. Moreover this rule, if promulgated, should result in an overall reduction in the filing burden on the oil pipeline companies as most of the proposed revisions either delete or consolidate the schedules presently including in the annual report.

V. Written Comment Procedures

The Commission invites interested persons to submit written data, views, and other information concerning matters set out in this notice. All comments in response to this notice should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should refer to Docket No. RM82–5. An original and 14 copies of such comments should be filed with the Commission by February 2, 1982.

All written submissions to this rulemaking will be placed in the Commission's public file and will be available for public inspection at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

(Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142 (1978); Interstate Commerce Act, 49 U.S.C. 1, et seq.)

In consideration of the foregoing, the Commission proposes to amend Part 357 of Subchapter R, Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 357—ANNUAL SPECIAL OR PERIODIC REPORTS; CARRIERS SUBJECT TO PART 1 OF THE INTERSTATE COMMERCE ACT

Section 357.2 is revised to read as follows:

§ 357.2 FERC No. 6, annual report of oil pipeline companies.

(a) *Prescription.* The form, Annual Report FERC Form No. 6 (Carriers by Pipeline), is prescribed for the year ending December 31, 1982, and for each year thereafter.

(b) *Filing Requirements.*—(1) *Who must file.* Each carrier by pipeline

[1] The deletion of Schedule 595 in no way affects the requirement to file a statement of the competitive bidding transaction under 49 C.F.R. Part 1010.

subject to the provisions of Section 20 of the Interstate Commerce Act, shall prepare and file with the Commission an original and conformed copies of FERC Form No. 6 pursuant to the General Instructions set out in that form.

(2) *When to file.* The report shall be filed on or before March 31st of the year following the year to which it relates.

The following Appendices A and B will not appear in the Code of Federal Regulations.

APPENDIX A

PROPOSED REVISIONS - FORM P

Title	Schedule No.	Retain - As Is	Revise Instructions	Delete Columns	Delete Complete Schedule	Explanation
Notice	-		X			In the final redesign format this page will become a part of the instructions, with minor editorial revisions. The title will be changed to "List of Schedules;" delete the page numbers; and add a column "Remarks" to indicate the schedules which are not applicable or omitted.
Table of Contents	-		X			
Identity of Respondent	101	X				
Directors	102		X	X		Revise instruction by deleting No. 2 to reflect the deletion of columns (c), (d), (e) and (f).
Principal General Officers	103					
Corporate Control Over Respondent	104	X		X		Delete column (d).
Stockholders Report	104A		X			
Voting Powers and Elections	105			X		To be included in the General Instructions with the non-filing reported in the List of Schedules.
Guaranties and Suretyships	110					Column (e) and (f) merged into one column for reporting preferred stocks
Comparative Balance Sheet Statement	200	X				
Notes to above	200	X			X	Minor editorial revision to the numbers
Income Statement	300	X				Moved to separate page and to include all notes to the financial statements on a single schedule.
Analysis of Federal Income and Other Taxes Deferred	300A	X				
Working Capital	302	X				
Notes and Remarks	-					
Unappropriated Retained Income Statement	305	X				Will be merged with one schedule to report all notes to the financial statements.
Dividend Appropriations of Retained Income	306			X		Delete columns (b) and (c).
Compensating Balances and Short-term Borrowing Arrangements	205				X	
Special Deposits	206				X	
Notes Receivable	210				X	
Receivables from Affiliated Companies	211	X				
Accounts Receivable	212				X	
General Instructions Concerning Returns in Schedules 220 and 221	-	X				
Investments in Affiliated Companies	220		X	X		Delete columns (e) through (h), (j) and (l).
Investments in Common Stocks of Affiliated Companies	220A	X				
Other Investments	221		X	X		Delete columns (d) through (g), (i) and (k).
Companies Controlled Directly by Respondent Other Than Through Title of Securities	222	X				
Companies Controlled Through Nonreporting Intermediaries	223				X	
Securities, Advances, and Other Intangibles Owned or Controlled through Nonreporting Carriers and Noncarrier Subsidiaries	224			X		Delete columns (c) and (e) and (g).
Sinking and Other Funds	225				X	
Carrier Property	230	X				
Depreciation Base and Rates - Carrier Property	231	X				
Depreciation Base and Rates - System	231a	X				
Accrued Depreciation - Carrier Property	232	X				
Accrued Depreciation - System Property	232A	X				

PROPOSED REVISIONS - FORM P

Title	Schedule No.	Retain - As is	Retain - Revise Instruction	Retain - Delete Columns	Delete Complete Schedule	Explanation
Amortization Base and Reserve	233	X				
Noncarrier Property	234	X				
Other Deferred Charges	240	X				
Rental Expense of Lessee	243					
Minimum Rental Commitments	244				X	
Lessee Disclosure	245				X	
Lease Commitments - Present Value	246				X	
Income Impact-Lessee	247		*		X	
Notes Payable	250				X	
Payables to Affiliated Companies	251	X				
Accounts Payable	252				X	
Long-Term Debt Payable Within One Year	253				X	
Long-Term Debt Payable After One Year	260		X	X		Except column (i) relocated to schedule 260
Long-Term Debt Changes During the Year	261				X	Delete columns (d) thru (h). Added one column for above
Security for Long-Term Debt	262				X	
Capital Stock	270			X		Delete columns (n), (o), (p), (r), (s) and (u). Revise
Capital Stock Changes During the Year	271		X			heading for column (v) to read " Book Value "
Stock Liability for Conversion of Securities of Other Companies	272				X	Revise title headings for columns (d) and (i) to read: Number of Shares.
Additional Paid-in Capital	274	X				
Appropriated Retained Income	275	X				
Operating Revenue Accounts	310	X				
Operating Expense Accounts	320	X				
Pipe-Line Taxes (Other Than Income Taxes)	330	X				
Income From Noncarrier Property	340			X		Delete column (d).
Abstracts of Terms and Conditions of Leases	342				X	
Interest and Dividend Income	345	X				
Miscellaneous Items in Income and Retained Income Accounts for the Year	360	X				
Statistics of Operations	400	X				
Miles of Pipe Line Operated at Close of Year	410	X				
Rentals	420				X	
Abstracts of Leasehold Contracts	427				X	
Employees and Their Compensation	561	X				
Compensation of Officers, Directors, etc.	562				X	
Payments for Services Rendered by Other Than Employees	563	X				
Important Changes During the Year	591	X				Schedule will be moved to the front of the form as part of the schedule for notes to financial statements.
Competitive Bidding - Clayton Antitrust Act	595				X	
Verification , Oath, Supplemental Oath	-		X			Delete the requirement for Notary and Supplemental Oath.
Memoranda (for use of Commission only)	-				X	
Index	-		X			Will be revised to reflect deleted schedules and renumbered schedules.
Statement of Changes in Financial Position	-					Schedule added to allow for a more complete financial presentation of the financial condition of the pipelines to compensate for the loss of deleted data.

* Data requirements will remain the same, with only a redesign in the format presentation.

SPECIMEN

Appendix B

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report
			Dec. 31, 19___

STATEMENT OF CHANGES IN FINANCIAL POSITION

1. This statement is not restricted to those items which are non-current in nature. It is intended that this statement be flexible enough in nature so that latitude can be given, under the classification of "Other," to allow for disclosure of all significant changes and transactions, whether they are within or without the current asset and liability groups.
2. If the notes to the funds statement in the respondent's annual report to stockholders are applicable in every respect to this statement, such notes should be attached to page 122.
3. Under "Other" specify significant amounts and group others.
4. Codes Used:
   (a) Such as net increase-decrease in working capital, etc., other than changes in short term investments shown as item 4(e).
   (b) Bonds, debentures and other long-term debt.
   (c) Net proceeds or payments.
   (d) Include commercial paper.
   (e) Identify separately such items as investments, fixed assets, intangibles, etc.
5. Enter on page 122 clarifications and explanations.

Line No.	SOURCES OF FUNDS (See instructions for explanation of codes) (a)	Amounts (b)
1	Funds from Operations	
2	Net Income	
3	Principal Non-Cash Charges (Credits) to Income	
4	Depreciation	
5	Amortization	
6	Provision for Deferred Taxes	
7	Other (Net)	
8		
9		
10		
11		
12	TOTAL Funds from Operations (Enter Total of lines 2 thru 11)	
13	Funds from Outside Sources (New Money)	
14	Long-Term Debt (b) (c)	
15	Capital Stock (c)	
16	Net Increase in Short-Term Debt (d)	
17	Other (Net)	
18		
19		
20		
21	TOTAL Funds from Outside Sources (Enter Total of lines 14 thru 20)	
22	Sale of Non-Current Assets (e)	
23		
24	Contributions from Associated and Subsidiary Companies	
25	Other (Net) (a)	
26		
27		
28	TOTAL Sources of Funds (Enter Total of lines 12, 21, 22 thru 27)	

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SPECIMEN

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 19___

STATEMENT OF CHANGES IN FINANCIAL POSITION (Continued)

Line No.	APPLICATION OF FUNDS (a)	Amounts (b)
29	Gross Additions to Carrier Property	
30	Gross Additions to Noncarrier Property	
31	Other	
32		
33		
34		
35		
36	TOTAL	
37		
38	Dividends on Capital Stock	
39	Funds for Retirement of Securities and Short-Term Debt	
40	Long-term Debt (b) (c)	
41	Redemption of Capital Stock	
42	Net Decrease in Short-term Debt (d)	
43	Other (Net)	
44		
45		
46	Purchase of Other Non-Current Assets (e)	
47		
48		
49	Investments in and Advances to Associated and Subsidiary Companies	
50	Other (Net) (a)	
51		
52		
53	TOTAL Applications of Funds (Enter Total of lines 36 thru 52)	

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 19___

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Changes in Financial Position, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages , such notes may be attached hereto.

SPECIMEN

[FR Doc. 81-35410 Filed 12-10-81; 8:45 am]
BILLING CODE 6717-01-C

¶ 32,184 High-Cost Gas Produced From Tight Formations (Texas-9 Addition II)

46 F. R. 62086 (December 22, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Texas—9 Addition II)]

High-Cost Gas Produced From Tight Formations; Notice of Proposed Rulemaking

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulation contains the recommendation of the Railroad Commission of Texas that an additional area of the Travis Peak Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on January 14, 1982.

Public Hearing: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on December 30, 1981.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8511 or Walter W. Lawson, (202) 357–8556.

SUPPLEMENTARY INFORMATION:

I. Background

On November 2, 1981, the Railroad Commission of Texas (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that an additional area of the Travis Peak Formation located in the northeastern part of the State of Texas and covering Railroad Commission Districts 5 and 6, be designated as a tight formation. The Commission previously adopted recommendations that the Travis Peak Formation in the Sym-Jac, West (Hosston) Field and the Bear Grass Area of east Texas be designated as tight formations (Docket No. RM79–76 (Texas—9) and (Texas—9 Addition), Order No. 154, issued June 10, 1981 and Order No. 18C, issued October 8, 1981, respectively). Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Texas' recommendation that this additional area of the Travis Peak Formation be designated a tight formation should be adopted. Texas' recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

Texas' recommended addition to the Travis Peak Formation is encountered in the northeastern part of the State of Texas, in the east Texas basin, and consists of all of Texas Railroad Commission Districts 5 and 6. This recommendation includes the previously designated areas of the Sym-Jac, West (Hosston) Field and the Bear Grass Area, both of which are located in Texas Railroad Commission District 5.

Accordingly, the description of the formation in the rule has been amended to consolidate the three Travis Peak recommendations. The Travis Peak Formation is the basal formation of the Lower Cretaceous series and overlies the Jurassic Cotton Valley Sands and is below the Pettit Formation. The area recommended for designation consists of Lower Cretaceous age, lenticular, alternating sandstone and shale beds. The top of the Travis Peak Formation is encountered immediately below the last limestone zone of the overlying Sligo/ Pettit Formation. The base of the Travis Peak is the top of the Cotton Valley Group, where a black shale zone is found. The top of the Travis Peak Formation is found at a depth of 3,140 feet in Lamar County, in the northern area of the east Texas basin, and at 10,850 feet in the southern area of Cherokee County, The Travis Peak Formation ranges in thickness from approximately 500 to 2,500 feet.

III. Discussion of Recommendation

Texas claims in its submission that evidence gathered through information and testimony presented at a public hearing convened by Texas on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Texas further asserts that existing State and Federal regulations assure that development of this formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No, RM80–68 (45 *FR* 53456, August 12, 1980), notice is hereby given of the proposal submitted by Texas that the Travis Peak Formation in Texas Railroad Commission Districts 5 and 6 as described and delineated in Texas' recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before January 14, 1982. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Texas–9 Addition II), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than December 30, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18 Code of Federal Regulations, as set forth below, in the event Texas' recommendation is adopted.

Kenneth A. Williams,

Director Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended in subparagraph (36) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

(36) *Travis Peak Formation in Texas.* RM79–76 (Texas–9).

(i) *Delineation of formation.* The Travis Peak Formation in the east Texas basin consists of the 47 counties that make up Texas Railroad Commission Districts 5 and 6. The area is irregular in shape. The northern boundary is the Texas-Oklahoma border. The eastern boundary is the Texas-Louisiana border.

The southern and western boundaries consist of the limits of Railroad Commission Districts 5 and 6.

(ii) *Depth.* The top of the Travis Peak Formation is found at a depth of 3,140 feet in Lamar County, in the northern area of the east Texas basin, and at 10,850 feet in the southern area of Cherokee County. The Travis Peak Formation ranges in thickness from approximately 500 feet to 2,500 feet.

¶ 32,185 High-Cost Gas Produced From Tight Formations (Wyoming-8)

46 F. R. 63321 (December 31, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Wyoming-8)]

High-Cost Gas Produced From Tight Formations; Wyoming

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This notice of proposed rulemaking by the Director of the Office of Pipeline and Producer Regulations contains the recommendation of the State of Wyoming that the Frontier Formation be designated as a tight formation under § 271.703(d).

DATE: Comments on the proposed rule are due on January 22, 1982.

PUBLIC HEARING: No public hearing is scheduled in this docket as yet. Written requests for a public hearing are due on January 7, 1982.

ADDRESS: Comments and requests for hearing must be filed with the Office of the Secretary, 825 North Capitol Street NE,. Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8317, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

I. Background

On December 14, 1981, the State of Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations (45 FR 56034, August 22, 1980), that the Frontier Formation located in Lincoln, Sublette, and Sweetwater Counties, Wyoming, be designated as a tight formation. Pursuant to § 271.703(c)(4) of the regulations, this Notice of Proposed Rulemaking is hereby issued to determine whether Wyoming's recommendation that the Frontier Formation be designated a tight formation should be adopted. The United States Geological Survey concurs with Wyoming's recommendation. Wyoming's recommendation and supporting data are on file with the Commission and are available for public inspection.

II. Description of Recommendation

The recommended formation is located north and east of the La Barge platform area in southwest Wyoming. The area contains about 222,720 acres and is in Lincoln, Sublette, and Sweetwater Counties, Wyoming. It encompasses all or part of Townships 25 and 26 North, Range 109 West; Township 29 North, Range 111 West; Townships 26 through 31 North, Range 112 West; and Townships 28 through 31 North, Range 113 West.

The vertical limits of the Frontier Formation are defined by the Baxter Shale Formation above and the Mowry Shale Formation below. The depth to the top of the formation averages 7,700 feet and gross thickness varies from 50 to 150 feet.

III. Discussion of Recommendation

Wyoming claims in its submission that evidence gathered through

information and testimony presented at a public hearing in Case No. 1, Order No. 1, Docket No. 53–81(A) convened by Wyoming on this matter demonstrates that:

(1) The average *in situ* gas permeability throughout the pay section of the proposed area is not expected to exceed 0.1 millidarcy;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production from the recommended formation, without stimulation, is not expected to exceed the maximum allowable production rate set out in § 271.703(c)(2)(i)(B); and

(3) No well drilled into the recommended formation is expected to produce more than five (5) barrels of oil per day.

Wyoming further asserts that existing State and Federal Regulations assure that development of this formation will not adversely affect any fresh water aquifers.

Accordingly, pursuant to the authority delegated to the Director of the Office of Pipeline and Producer Regulation by Commission Order No. 97, issued in Docket No. RM80–68 (45 FR 53456, August 12, 1980), notice is hereby given of the proposal submitted by Wyoming that the Frontier Formation, as described and delineated in Wyoming's recommendation as filed with the Commission, be designated as a tight formation pursuant to § 271.703.

IV. Public Comment Procedures

Interested persons may comment on this proposed rulemaking by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C., 20426, on or before January 22, 1982. Each person submitting a comment should indicate that the comment is being submitted in Docket No. RM79–76 (Wyoming–8), and should give reasons including supporting data for any recommendations. Comments should include the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C., during business hours.

Any person wishing to present testimony, views, data, or otherwise participate at a public hearing should notify the Commission in writing that they wish to make an oral presentation and therefore request a public hearing. Such request shall specify the amount of time requested at the hearing. Requests should be filed with the Secretary of the Commission no later than January 7, 1982.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3342))

Accordingly, the Commission proposes to amend the regulations in Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations as set forth below, in the event Wyoming's recommendation is adopted.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

PART 271—CEILING PRICES

Section 271.703(d) is amended by adding new subparagraph (84) to read as follows:

§ 271.703 Tight formations.

* * * * *

(d) *Designated tight formations.* The following formations are designated as tight formations. A more detailed description of the geographical extent and geological parameters of the designated tight formations is located in the Commission's official file for Docket No. RM79–76, subindexed as indicated, and is also located in the official files of the jurisdictional agency that submitted the recommendation.

* * * * *

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(60) through (83) [Reserved]

(84) *Frontier Formation in Wyoming. RM79-76 (Wyoming-8)*—(i) *Delineation of formation.* The Frontier Formation is found in Lincoln, Sublette, and Sweetwater Counties, Wyoming, encompassing all or parts of Townships 25 and 26 North, Range 109 West; Township 29 North, Range 111 West; Townships 26 through 31 North, Range 112 West; and Townships 28 through 31 North, Range 113 West.

(ii) *Depth.* The Frontier Formation's vertical limits are defined by the Baxter Shale Formation above and the Mowry Shale Formation below. The gross thickness of the formation varies from 50 to 150 feet. The average depth to the top of the Frontier Formation is 7,700 feet.